Coherency Based Equivalents for Long-Term Dynamic Studies

by

Mohammed Arif Abdul Majeed

A Thesis Presented to the

FACULTY OF THE COLLEGE OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

In

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Abdul Majeed, Mohammed Arif, M.S.

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U·M·I
300 N. Zeeb Rd.
Ann Arbor, MI 48106

University of Petroleum and Minerals

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This thesis, written by **Mohammed Arif Abdul Majeed** under the direction of his Thesis Committee, and approved by all its members, has been presented to and accepted by the Dean, College of Graduate Studies, in partial fulfillment of the requirements for the degree of **Master of Science in Electrical Engineering**.

Dean, College of Graduate Studies

Date: 25/5/85

Department Chairman

THESIS COMMITTEE

Dr. C.B. Somuah, Chairman

Dr. A.H. El-Abiad, Member

Dr. I.M. El-Amin, Member

To my parents

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الموجـــــــز

تعتبر المكافئات الديناميكية نماذج للمعادلة التفاضلية ذات الدرجة المنخفضة للخواص الديناميكية كشبكة الطاقة . يتم تشكيل النموذج ذو الدرجة المنخفضة تجميع مجموعة من وحدات الطاقة (مجموعة مترابطة) بحيث تتذبذب معا عند حدوث اضطراب معيـــــن .
تحتوى كل وحدة طاقة على آلة توافقية ،نظام اثارة ،توربين ،أداة الضبط ونموذج لمرجل .

ويمكن تحديد محيط آلة توافقية مشابهة الطراز مع نظام حث واداة تحكم وتوربين ومرجل لكل مجموعة متجانسة بواسطة التربيع الاصغر للتوابع الانتقالية . وقد تـــم تحديد تقنية الحث لعدد ثلاثة مصانع للطاقة .

ويتم تقييم دقة النموذج المصغر بمقارنة التجاوب الزمنى لنموذج مماثل مع تجاوب كامل نظام الطاقة الزمنى بمعدل ٣٩ وحدة للنظام الانجليزى .

ABSTRACT

Dynamic equivalents are reduced order differential equation models of the dynamic characteristics of a power system. The reduced order model is formed by lumping together group of power plant units (coherent group) which tends to swing together for a given perturbation. Each power plant unit is represented as constituted by a synchronous machine, an excitation system, a turbine, a governor and a boiler models. The equivalent units are made up of similar models.

The parameters of an equivalent model of synchronous machine, excitation system, governor, turbine and boiler are identified for each group of coherent units, by means of a least square fit of their transfer functions. The aggregation technique is demonstrated for a group of three power plant units. The accuracy of the reduced order model is evaluated by comparing time responses of the equivalent model with the response of the full power system model, for 39 bus New England System.

Chapter I

INTRODUCTION

1.1 BACKGROUND

Major disturbances resulting from equipment outages such as the loss of a large generating unit, transmission line or load when followed by multiple cascading events tends to subject the power system components to severe stress which can lead to total system collapse. Recently attention is being focused on power system dynamic studies which extend beyond the 2 to 4 second period covered in the transient stability studies into the long term dynamics period with a period up to 20 minutes. The long term dynamics is concerned with the energy balance throughout the system and as such includes the dynamics of the turbine, boiler, auxilliaries and critical protective relays.

The most practical method used to study the long term dynamics is usually simulation of the dynamic power system model. However the dynamic simulation of a power system, involves numerical integration of a very large set of nonlinear differential equations which are coupled by algebraic equations describing the transmission network. With the development of large interconnections, power systems can no longer be studied in isolation. Owing to the dimensions of the interconnected systems it is not economical to represent the entire system in details. Simple equivalents which represent those part of the system (external system) which influence the part of the system under study (study system) but whose internal performance is not under study are desirable.

1.2 REVIEW OF RESEARCH

Several researchers have worked on the problem of developing dynamic equivalents. Three main lines of research are being pursued in the search for dynamic equivalents. First, the modal analysis technique [4-6], second, the system identification technique [7-9] and third, the coherent generator technique [10-15].

1.2.1 Modal Analysis Technique

This technique recognizes the existences of decoupled natural frequencies or modes within the system which are present in the state. The state variable corresponding to the modes which are deemed to have a negligible effect on the study system are eliminated to form the dynamic equivalent. The technique requires the computation of eigenvalues, which appears as the major obstacle in applying this approach to a large system with several generating units when the model of each unit may typically have 10 to 20 state variables. The reduced system of differential equations obtained by this technique cannot be interpreted, in general, since the new state variables do not have physical significance. Thus, the reduced model obtained by model analysis cannot be used without modification to conventional stability programs.

1.2.2 System Identification Technique

This technique consists of comparing measurements from a real system which is undergoing random perturbation with the same measurements made on a hypothesized reduced order model of the system and adjusting the model parameters to minimize the difference. Since power system are constantly being perturbed by random load changes, the system identification technique can be used to identify the parameters of the equivalent. The parameter synthesis is done using maximum likelihood concept or by minimizing some error function. Implementation of these techniques requires lengthy calculation and a powerful computer, with the risk of defeating the purpose of equivalent. Although these techniques have proved useful to obtain equivalent parameters of small groups of machines, the procedures reported in the literature have failed to work when confronted with large section of power system.

1.2.3 Coherent Generator Technique

This technique reduces the order of the system by lumping together groups of generators which tend to swing together for a given perturbation. The reduced model obtained by this technique, has a physical correspondence with the original power system. Therefore, the existing stability programs, which have been perfected over the years, can be readily used in simulation of the reduced order model. Coherency methods must solve two problems. Firstly, they must provide ways of easily recognizing the coherent groups of generators. Secondly once the groups are identified, they must provide ways of aggregating the individual generating units into an equivalent machine. The effort required and the accuracy obtained will depend on the method used to solve these two problems..

1.3 REVIEW OF THE EQUIVALENCING PROCEDURE

The overall procedure for forming coherency based dynamic equivalent is briefly reviewed. The procedure involves three basic steps:

(a) Identification of group of coherent generators.

(b) Network reduction.

(c) Dynamic aggregation of power plant models.

1.3.1 Identification of Coherent Generators

Two generators are defined as coherent if their angular difference is constant within a certain tolerance over a certain interval. The coherency of both generator internal and terminal buses is of interest. The coherency of generator terminal bus forms the basis for network reduction step. The coherency of internal bus is assumed in dynamic aggregation step. Several techniques have been proposed for identification of coherent generators. The distance measure technique [10] suggested by Lee et al, evaluates the admittance distance and reflection distance (measure of synchronizing power) between generators, using network and machine information. These measures are combined and used as features for a pattern recognition approach to coherency recognition. The singular point method [11] examines the change in relative machine angles from a singular or equilibrium point of the system differential equation to another. This change in angle is used as a guide for coherency recognition. The weighted eigenvector method [14] evaluates the closed form solution of the linearised swing equation in terms of weighted eigenvectors. The coherency indices which are derived from these eigenvectors, ascertains coherency among the generators. The rate of change of kinetic energy method [15] evaluates the machine condition at a clearance time closed to the critical one, which serves as a guide for coherency recognition. The method of linear simulation [13] suggested by Podmore for identifying coherent generators is based upon formulation of a simplified model of power system, which is solved using a fast trapezoidal algorithm. The approximate swing curves so obtained are processed by a clustering algorithm to determine coherency.

1.3.2 Network Reduction

The network reduction consists of reducing generator buses based upon coherency and reduction of load buses.

The coherency based reduction of generator buses, replaces the terminal buses, for each group of coherent generator by a single equivalent bus. The generation load and shunt admittance on the coherent buses are transfered and summed on the equivalent bus. The Gaussian elimination procedure is applied for the reduction of the load buses. Although this method effectively reduces the number of buses, there is no guarantee that the number of lines will also decrease. Sparsity technique are then applied to the network reduction problem, in order to minimize the number of branches which are introduced in the equivalent network.

1.3.3 Dynamic Aggregation of Power Plant Models

The coherency based reduction of generator terminal buses has the effect of placing generating units from different stations on the same equivalent bus. The reduction of system dynamic order is achieved by combining the parallel generating units and the prime movers. This procedure is called dynamic aggregation. The criteria for an acceptable equivalent model of power plants, from dynamic point, is that its electric power output response matches the total electric power output of the individual power plant it replaces, and the voltage response at its terminal bus matches the voltage response of the bus with individual plant models.

The aggregation method relies upon the consideration that the plants to be aggregated, being attached to the same bus, have the same terminal voltage, and the assumption that these plants, being coherent, have the same speed. Each power plant is represented as constituted by a synchronous machine, an excitation system, a turbine, a governor and a boiler. The equivalent plants are made up of similar models. The basic concept of the aggregation procedure is explained in the following paragraph, by considering the simple case of aggregating the governor-turbine models.

The problem of aggregation of the governor-turbine models is to identify the parameters of an equivalent governor-turbine model, with the objective that its output approximates as closely as possible the total power output for the coherent group, if the same speed signal is applied as input. Assuming a speed variation of small amplitude the problem is solved as follows: nonlinearities in the governor-turbine model are ignored, the transfer function of each individual governor-turbine model is calculated for discrete values of the frequency in the range of 0.01 to 10.0 hz., which is of practical importance, and these transfer functions are added. This corresponds to having the individual governor-turbine block diagrams in parallel as shown in Fig. 1.1. The summation of transfer function is called the "aggregated transfer function". A model for equivalent governor-turbine is chosen and its

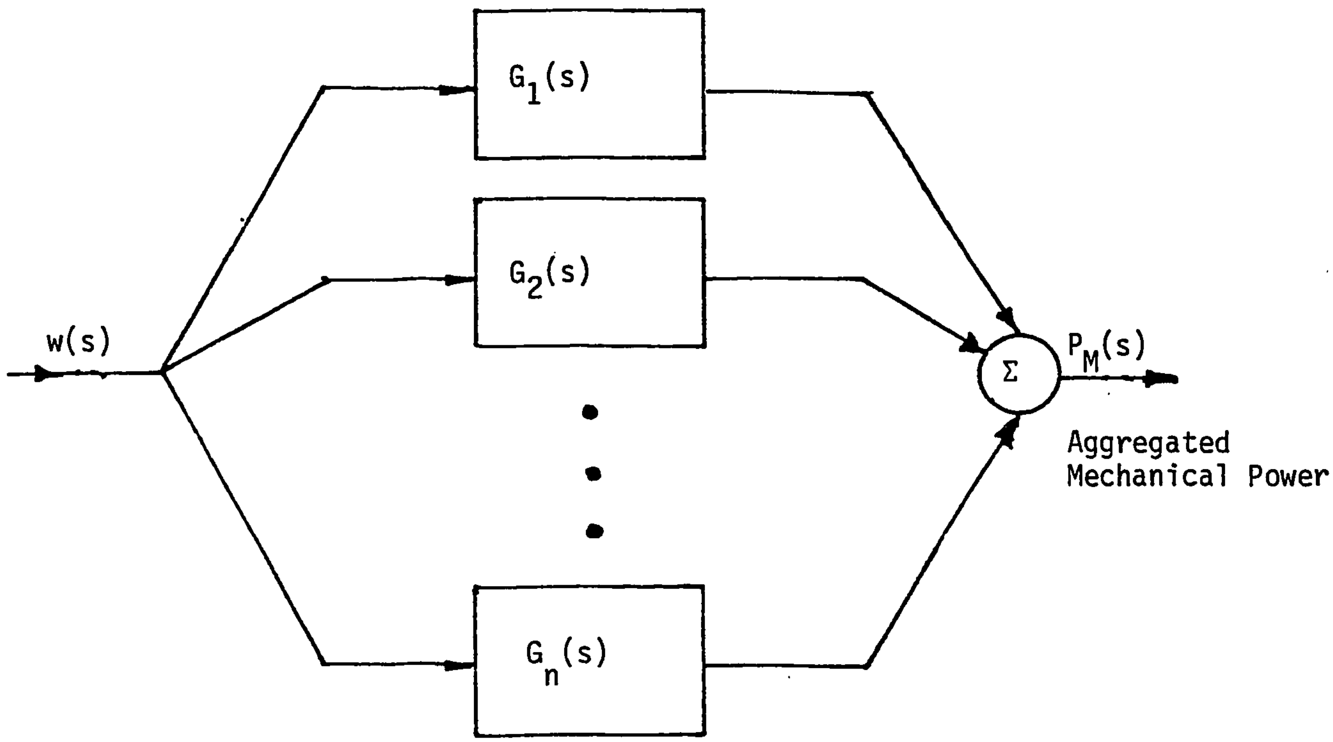


Figure 1.1 Aggregation of the Governor Turbine Systems

parameters are adjusted until its transfer function fits the "aggregated transfer function" within a specified accuracy. Numerical technique such as gradient search is used for adjusting these parameters. The objective function that is minimized is the sum, over the frequency range, of the square of the relative error between the equivalent and the aggregated transfer function. The non-linear features of the equivalent model, such as gate limit and gate velocity limit, are evaluated separately by calculating the effect of step input.

The same principle of transfer function fitting is applied for aggregation of synchronous machine, the excitation system and the boiler models, only the method to find the "aggregated transfer function" will change depending upon input and output relationships.

1.4 MOTIVATION AND OBJECTIVE

From the literature reviewed it is clear, that almost all the efforts in the developments of dynamic equivalents have been for the equivalent which can be used in transient stability studies, therefore there is a need for dynamic equivalent which can be used for long term dynamic (or energy balance) studies in a power system.

This thesis is directed towards the achievement of the following objectives:

1. Extension of coherency based model reduction technique [16] to include boiler control, boiler dynamics and power plant auxiliaries.

2. Study applicability and accuracy of the equivalent model in comparison with unreduced system.

3. Study the sensitivity of equivalent model to the operating point and the variation in power plant parameters.

Chapter II

DYNAMIC AGGREGATION OF POWER PLANT MODEL

2.1 INTRODUCTION

2.1.1 Background

The objective of this chapter is to describe the method of grouping power plant models that are coherent into an equivalent power plant model.

The coherency-based model reduction technique was suggested by Germond et al [16] for the reduction of Governor-Turbine, Synchronous machine and Excitation system models for use in transient stability studies. This technique is extended in this thesis to include boilers controls, boiler dynamics and power plant auxiliaries for use in long term dynamic studies.

The method considers separately the linear parameters and the nonlinear limits of the power plant models. First the aggregated transfer functions relating to the total mechanical and electrical power output of the coherent power plant units to their common speed and terminal voltage are calculated for several discrete frequencies. The parameters of the equivalent transfer functions are adopted to match the aggregated transfer function with a minimal error. Then the equivalent limits are calculated.

2.1.2 Assumptions and Overview of the Method

The assumptions are made that the coherent power plant units are on common bus, with the same terminal voltage V_T and have the same speed ω.

Each power plant unit is represented as constituted by a synchronous machine, an excitation system, a governor-turbine system and a boiler and boiler control system.

The block diagram in Fig. 2.1 represents the functional relationship between the mechanical and electrical output of an individual power plant unit and its speed ω and terminal voltage V_T, these being considered as input variables.

A similar block diagram is used to model an equivalent power plant unit, with the individual mechanical power replaced by total mechanical power and the electrical power by the total electric power output of the group.

The objective of the method is to specify the characteristics of the equivalent model, given the model of individual unit. This will be done by considering separately the rotor dynamics, the governor-turbine model, the boiler and boiler control model, the synchronous machine model and the excitation system model.

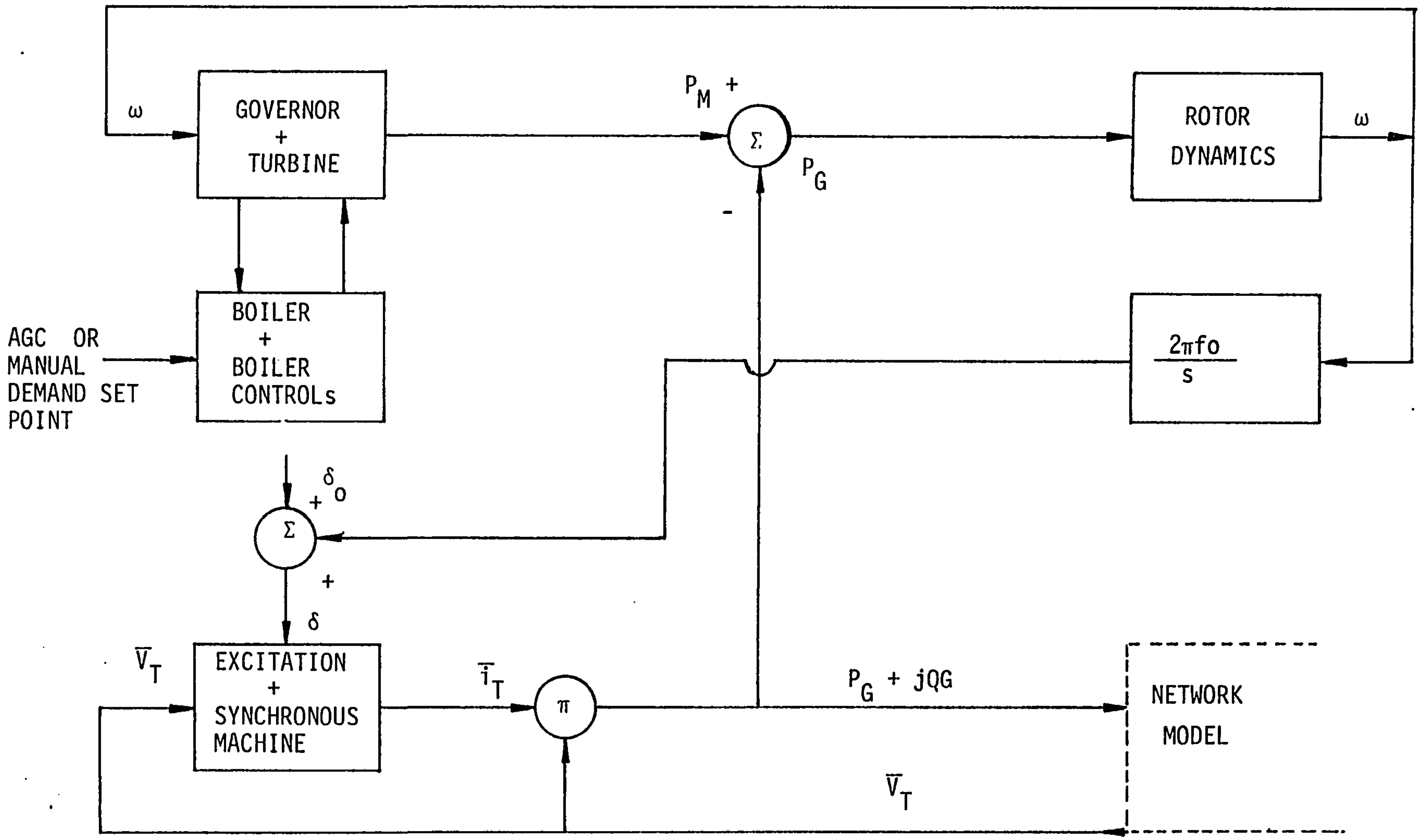


Figure 2.1 Power Plant Model

The linear parameter and nonlinear limits of each power plant components are considered separately, the linear parameter are further divided into steady state parameters and the dynamic parameters. The steady state parameters are those parameters which can be evaluated by substituting $S = j0$ in the aggregated and equivalent transfer function and the error between the two should be zero. The dynamic parameters are those linear parameters which are estimated by matching the aggregated and the equivalent transfer function with a minimal error for discrete value of the complex frequencies.

The frequency range, while evaluating the dynamic parameters depends upon the values of the highest and lowest time constant involved in the transfer function. The selection of the frequency range and data points, is done such that the effect due to all the time constant involved is taken into account while estimating the parameters.

2.1.3 General Concepts of Transfer Function Aggregation

The way the transfer functions are aggregated for the power plant individual components model, depends upon the input and output of the transfer function for the individual and equivalent units.

Depending upon relationship between the input/output of the individual units and the equivalent, the aggregation of transfer function can be divided into three classes.

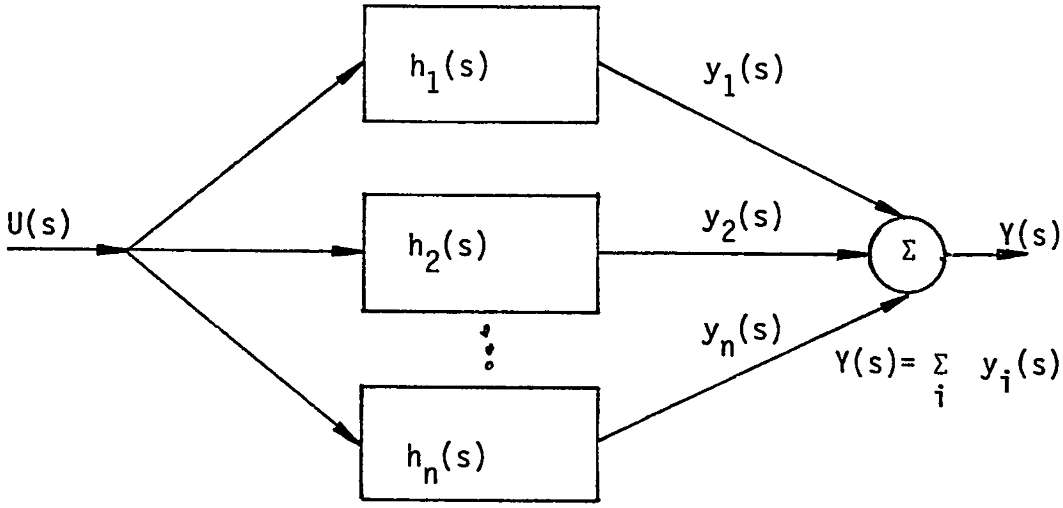
Class I type, if the inputs to all the individual and equivalent model are the same and the sum of the outputs of the individual models is the output of the equivalent model, then the aggregated transfer function for the equivalent model is the sum of the individual transfer function, this is shown in Fig. 2.2a.

Class II types, if the outputs of the individual and equivalent models are the same and the sum of the inputs of the individual models is the input of the equivalent model, then the inverse of aggregated transfer function for the equivalent is the inverse sum of the individual transfer function, this is explained in Fig. 2.2b.

Class III type, if the input to all the individual and equivalent models are the same and the weighted sum of the individual models output is the output of the equivalent model, then the aggregated transfer function is the weighted sum of the individual transfer function, this is shown in Fig. 2.2c.

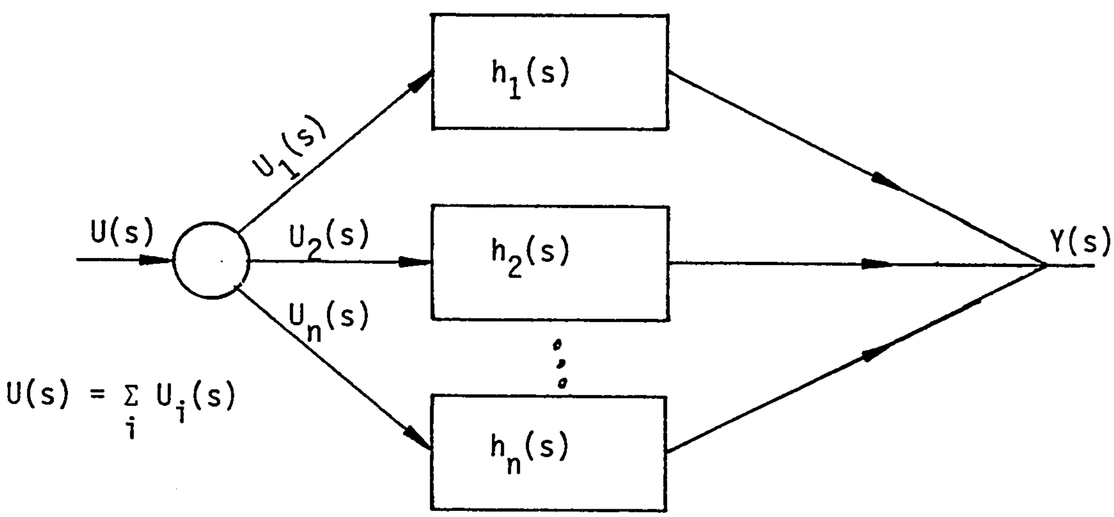
2.1.4 Overview of the Parameter Estimation Program

The dynamic parameters are evaluated by the parameter estimation program. The program first calculates the transfer function of each component of the individual power plant model for discrete complex frequencies and sum it up for all the coherent units. The result is the aggregated transfer function. Standard values are assigned to the unknown parameters of each component of the equivalent power plant model and the equivalent transfer function is calculated for the same frequencies.



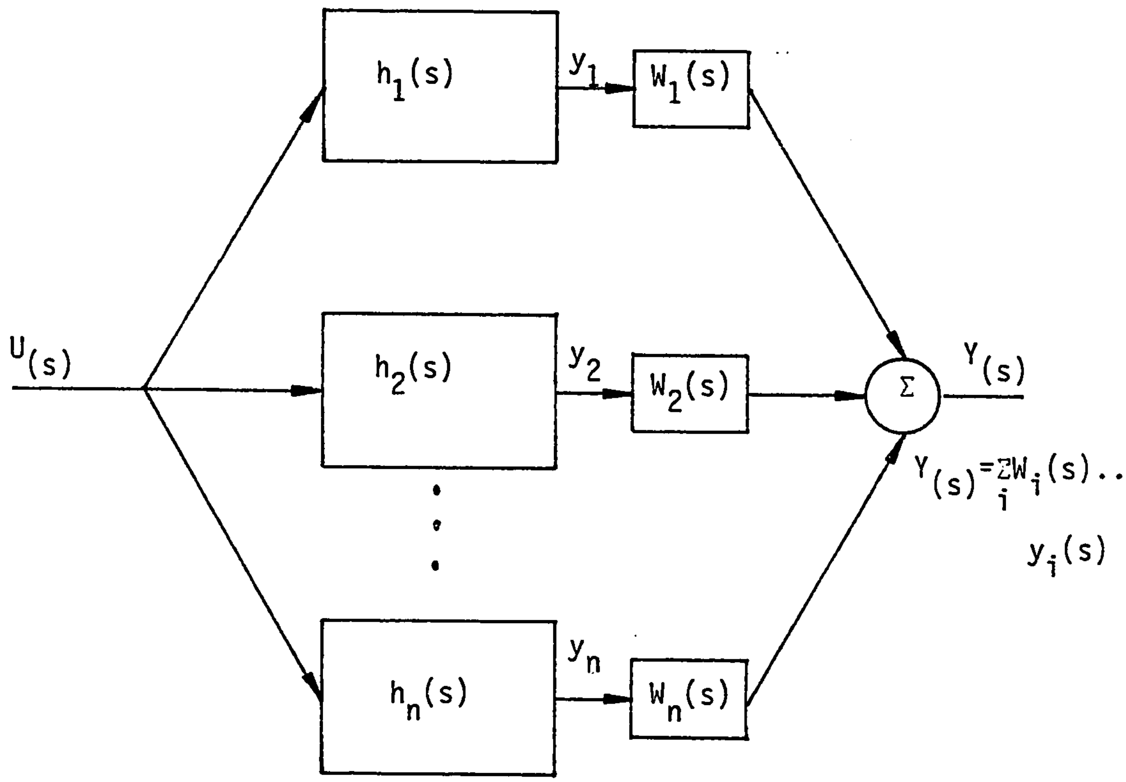
AGGREGATE TRANSFER FUNCTION $H(s) = \dfrac{Y(s)}{U(s)} = \sum_i h_i(s)$

Figure 2.2a Block Diagram Showing Aggregation of Transfer Function for Class 1 Type



AGGREGATE TRANSFER FUNCTION $H(s) = \dfrac{Y(s)}{U(s)} = \left[\sum_i 1/h_i(s)\right]^{-1}$

Figure 2.2b Block Diagram Showing Aggregation of Transfer Function for Class 2 Type.



AGGREGATED TRANSFER FUNCTION $H(s) = \frac{Y(s)}{U(s)} = \left[\sum_i W_i(s)\, h_i(s)\right]$

Figure 2.2c Block Diagram Showing Aggregation of Transfer Function for Class 3 Type.

The error to be minimized is the sum of the squares of the magnitude of the relative difference between these transfer functions. Marquardt [18] gradient technique is used for correcting the unknown parameters to minimize this error.

2.2 AGGREGATION METHOD

2.2.1 Rotor Dynamics

The swing equation for a single machine is

$$2H_j \frac{d\omega_j}{dt} = P_{Mj} - P_{Gj} - D_j\,\omega_j \tag{2.1}$$

with

ω	p.u. speed deviations
H	inertia constant in MWS/MVA
P_M	p.u. mechanical power
P_G	p.u. electromagnetic power
D	damping factor

Since all the machines of a coherent group have, the same speed deviations ω, equations (2.1) are summed up for all machines of the group to form the swing equation (2.2) of the equivalent generator turbine.

$$\left(\sum_j 2\,H_j\right)\frac{d\omega}{dt} = \sum_j P_{Mj} - \sum P_{Gj} - \left(\sum_j D_j\right)\omega \qquad (2.2)$$

All parameters being referred to the same base MVA.

The equivalent inertia constant is the sum of the individual inertia constants. or

$$^{(X)}H^{*} = \sum_j H_j \qquad (2.3)$$

The equivalent damping factor is the sum of the individual damping factors or

$$D^{*} = \sum_j D_j \qquad (2.4)$$

2.2.2 Turbine-Governor and Boiler Model

The open loop transfer function to be approximated by the equivalent model is $\Sigma\, P_M/\Delta\omega$ for the turbine-governor and boiler model.

The equivalent is formed in two steps. First the transfer function is aggregated assuming boiler pressure is constant over the range of interest this provides the parameter for governor and turbine models.

(X) The symbol * indicates equivalent variable and parameters.

Then the parameter of equivalent boiler and boiler control models are estimated.

Aggregation of Governor–Turbine Model

Assuming boiler pressure is constant over the range of interest, also assuming a speed deviation of small amplitude, the value and rate limits are neglected and a linear transfer function:

$$G_j(s) = \Delta P_{Mj}(s)/\Delta\omega(s) \tag{2.5}$$

where $\Delta\omega = (\omega\ \text{ref} - \omega)$ denotes the generator speed error, can be calculated for each power plant unit. Since the input speed deviation is the same for each generating unit of a coherent group, the total mechanical power for the coherent group is

$$\Delta P_M(s) = \sum_j \Delta P_{Mj}(s) = [\sum_j G_j(s)] \cdot \Delta\omega(s) \tag{2.6}$$

The transfer function $G_j(s)$ of equation (2.5) consist of two elements in series, the governor transfer function:

$G_G(s) = \dfrac{\Delta m(s)}{\Delta\omega(s)}$ and the turbine transfer function:

$$G_T(s) = \frac{\Delta P_M(s)}{\Delta\, m(s)}$$

Governor Transfer Function

Assuming a speed deviation of a small amplitude and a constant boiler pressure, the nonlinear limits are also neglected, a steam governor (Figure 2.3) transfer function is given by

$$G_G(s) = \Delta m(s)/\Delta\omega(s) =$$

$$\frac{-(K_3+SK_4)\,K_1\,(1+ST_{CH})\,\psi_{t0}}{R_1[(1+2K_{sh}moAvo)\,s\,(1+ST_G)(1+ST_{CH})-(K_3+SK_4)\,K_2\psi_{t0}}$$

(2.7a)

The values of constant K_1 through K_4 depend on the type of units used and is discussed in Chapter 3, we will use a turbine without first stage pressure feed back, this is only used to demonstrate the aggregation procedure and can be extended for all type of governors, the transfer function for this type of governor is given by

$$G_G(s) = \Delta m(s)/\Delta\omega(s) = \frac{-\psi_{t0}}{R_1(1+2K_{sh}moAvo)\,(1+T_G S)} \qquad (2.7b)$$

Steam Turbine Transfer Functions

Tandem compound single reheat turbine (Figure 2.4) is used, but the method of aggregation can be extended for all types of steam turbines.

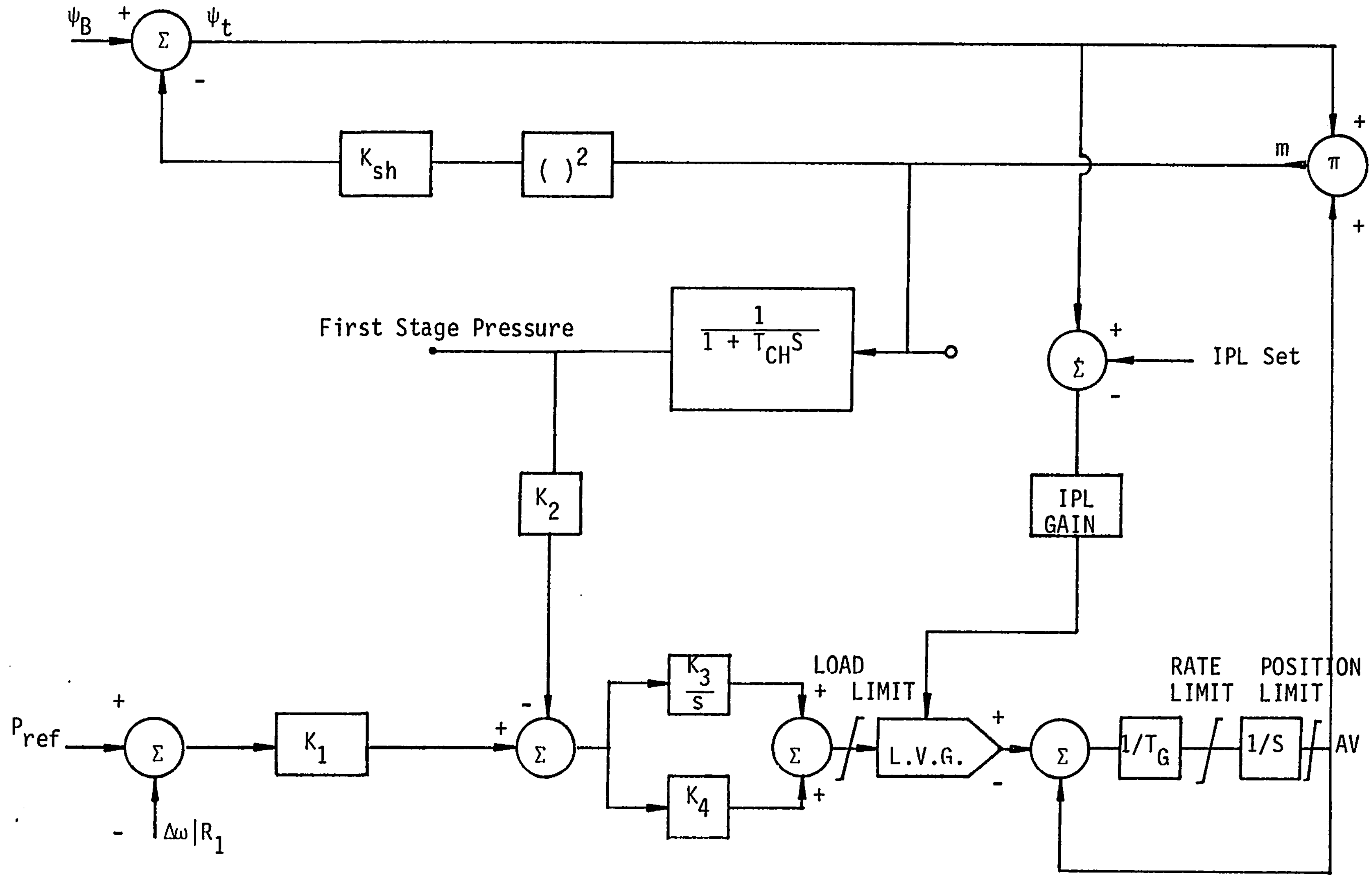


Figure 2.3 Block Diagram of Type 'E' Governor/Turbine Model.

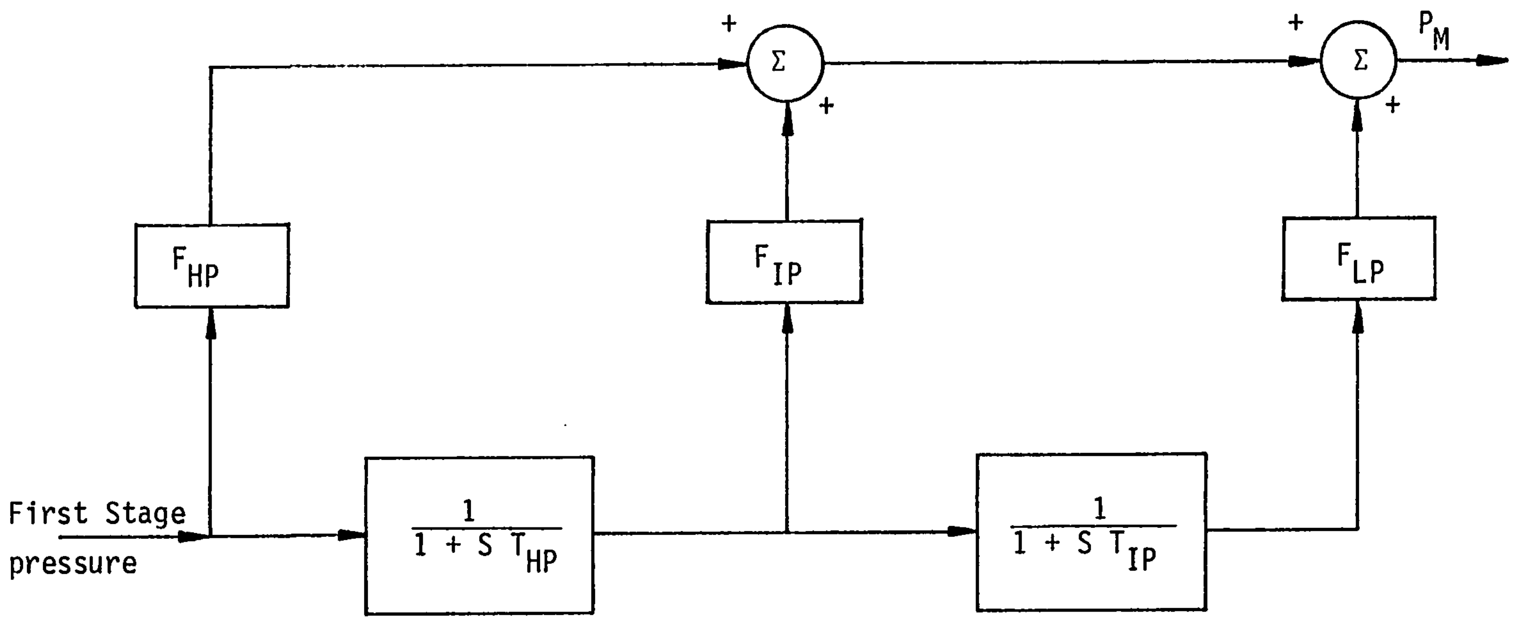


Figure 2.4 Block Diagram of Turbine Model.

The transfer function is:

$$G_T(s) = \frac{\Delta P_M(s)}{\Delta m(s)} = \frac{1}{(1 + ST_{CH})} \cdot$$

$$[F_{HP} + \frac{F_{IP}}{(1+ST_{HP})} + \frac{F_{LP}}{(1+ST_{HP})(1+ST_{IP})} \qquad (2.8)$$

For each governor and turbine, the transfer function G_G and G_T are evaluated numerically for discrete values of the variables $S=j\omega$ along the imaginary axis. The aggregated transfer function $P_M(s)/\Delta\omega(s)$ is obtained by summing of the individual governor-turbine transfer functions.

2.2.3 Equivalent Turbine and Governor Models

For the equivalent governor-turbine model, tandem compound single reheat turbine is used and was chosen as the same model is used for the individual units.

The transfer function of an equivalent governor-turbine is given as

$$G^*_{GT}(s) = \frac{\Delta P_M(s)}{\Delta\omega(s)} = [\frac{-\psi_{t0}}{R^*_1(1+2K^*_{sh}\,\text{moAvo})(1+ST^*_G)(1+ST^*_{CH})}] \bullet$$

$$[F^*_{HP} + \frac{F^*_{IP}}{(1+ST^*_{HP})} + \frac{F^*_{LP}}{(1+ST^*_{HP})(1+ST^*_{IP})}]$$

The parameters R_1^*, F_{HP}^*, F_{IP}^*, F_{LP}^* and K_{Sh}^* are steady state parameters.

To evaluate the steady state parameters we substitute S = j0 in the block diagram of the Governor turbine model, the nonlinear limits are also neglected. The block diagram is broken up into sub units which summed up for the individual governor and turbine and are matched with corresponding sub unit of the equivalent governor-turbine.

The equivalent governor droop is given by

$$\frac{\Delta\omega}{R_1^*} = \sum_j \frac{\Delta\omega}{R_{1j}} \qquad (2.10)$$

Similarly the turbine constant for the equivalent model are given by

$$F_{HP}^* = \sum_j F_{HPj} \qquad (2.11)$$

$$F_{IP}^* = \sum_j F_{IPj} \qquad (2.12)$$

$$F_{LP}^* = \sum_j F_{LPj} \qquad (2.13)$$

where all the parameters are on the same base.

After estimating the above constant the superheater frictional coefficient K_{sh}^* is estimated using the following expression:

$$\frac{\Delta P_M(0)}{\Delta\omega(0)} = \left[\frac{-\psi_{t0}}{R^*_1(1+2\ K^*_{sh}\ \text{mo Avo})}\right] \cdot [F^*_{HP} + F^*_{IP} + F^*_{LP}]$$

$$= \sum_j \left[\frac{-\psi_{t0}}{R_1(1+2K_{sh}\text{mo Avo}}\right]_j \cdot [F_{HP} + F_{IP} + F_{LP}]_j$$

Now the unknown parameters are, T^*_G , T^*_{CH} , T^*_{HP} and T^*_{IP}. These parameters are adjusted for the aggregated transfer function and the equivalent transfer function to obtain a minimal error, the estimation is done using the parameter estimation program.

Non Linear Parameters

The value limit for the equivalent model is calculated as the sum of the individual gate limit.

The maximum opening gate velocity of the equivalent model is the average of these parameters, weighted by the gate limit of the individual units. The maximum closing gate velocity is calculated in the same manner.

The load limit for the equivalent model is calculated as the sum of the individual load limit.

The initial pressure limiter (IPL) can only be aggregated if they have the same IPL set points, the IPL Gain for the equivalent model is calculated as the sum of the individual IPL Gain.

2.2.4 Aggregation of Boiler Model

As seen earlier the open loop transfer function to be approximated by the equivalent model is $\Sigma\Delta\ P_M(s)/\Delta\omega(s)$ for the turbine-governor and boiler model, while aggregating the turbine governor model we have assumed that the boiler pressure remains constant over the range of interest. However this assumption is not valid if we consider boiler dynamics. The aggregation of the boiler model follows the same pattern as the aggregation of the turbine-governor model.

Assuming a small speed variation and neglecting the nonlinear limits and the boiler auxiliary function the transfer function for the turbine governor and boiler model is

$$G_j(s) = \Delta P_{Mj}(s)/\Delta\omega(s) \tag{2.14}$$

The total mechanical power for the coherent group is

$$\Delta P_M(s) = \sum_j \Delta P_{Mj}(s) = [\sum_j G_j(s)] \bullet \Delta\omega(s) \tag{2.15}$$

The transfer function $G_j(s)$ of equation (2.14) consists of two element in series, the governor-boiler transfer function:

$G_{GB}(s) = \dfrac{\Delta m(s)}{\Delta \omega(s)}$ and the turbine transfer function:

$$G_T(s) = \frac{\Delta P_M(s)}{\Delta m(s)}$$

Governor-Boiler Transfer Function

The drum type boiler model (Figure 2.5) is used for all the individual machines, the aggregation procedure can also be extended to a once through boiler. A linear governor-boiler model transfer function is given by:

$$G_{GB}(s) = \Delta m(s)/\Delta \omega(s) = \frac{-\psi_{to}}{R_1(1+T_G S)(1-\Lambda A vo)} \tag{2.16}$$

where

$$\Lambda = \left[\frac{\{S(1+\frac{T_R}{10}S)\}\{e^{-DS}-(1+T_F S)-2K_{sh}mo\ C_D\ S(1+T_F\ S)\}}{\{C_D S^2(1+\frac{TR}{10}S)(1+T_F S)\}+\{(K_I+K_P S)(1+T_R S)\ e^{-DS}\}}\right] \tag{2.17}$$

The steam turbine transfer function is the same as that used in aggregation of turbine-governor model and is given by equation (2.8).

Similarly for each governor-boiler and turbine, the transfer function $G_{GB}(s)$ and $G_T(s)$ are evaluated numerically for discrete S along the imaginary axis. The aggregated transfer function $\Delta P_M(s)/\Delta \omega(s)$ is formed by summing of the individual governor-boiler and turbine transfer function.

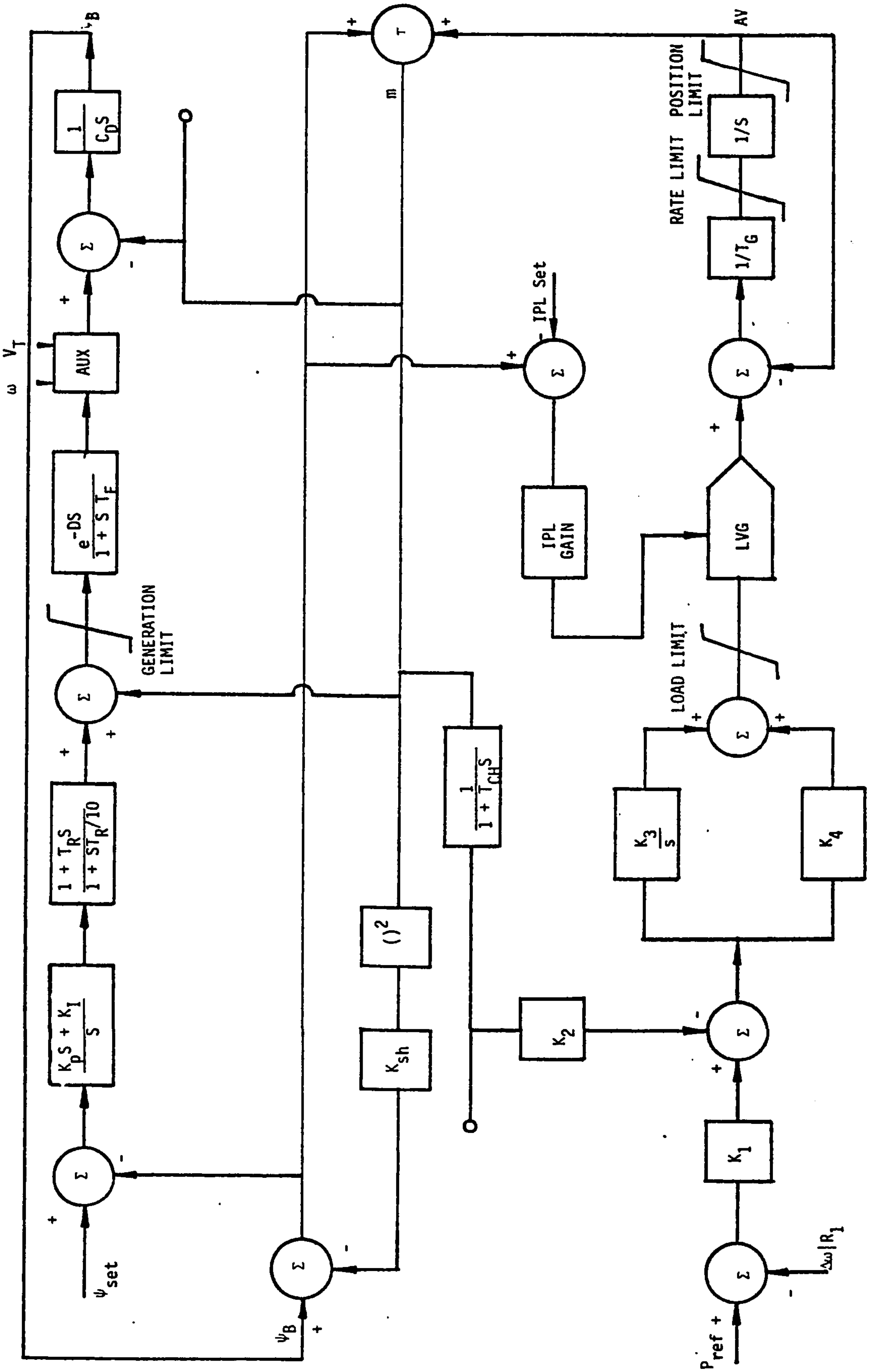


Figure 2.5 Block Diagram of Governor and Boiler Model

2.2.5 Equivalent Boiler Models

The drum type boiler model is used for the equivalent boiler as the individual boilers are also drum type.

The transfer function of an equivalent governor-turbine and boiler model is given by:

$$G^*_{GBT}(s) = \frac{\Delta P_M(s)}{\Delta\omega(s)} = \left[\frac{-\psi_{to}}{R^*_1(1-\Lambda^* Avo)(1+ST^*_G)(1+ST^*_{CH})} \right] \bullet$$

$$\bullet \left[F^*_{HP} + \frac{F^*_{IP}}{(1+ST^*_{HF})} + \frac{F^*_{LP}}{(1+ST^*_{HP})(1+ST^*_{IP})} \right] \qquad (2.18)$$

where

$$\Lambda = \left[\frac{\{S(1+\frac{TR^*}{10}S)\}\{e^{-D^*S} - (1-T^*_F S) - 2K^*_{sh}mo\, C^*_D S(1+T^*_F S)\}}{\{C^*_D S^2(1+\frac{TR^*}{10}S)(1+T^*_F S)\} + \{(K^*_I + K^*_P S)(1+T^*_R S)\, e^{-D^*S}\}} \right]$$

$$(2.19)$$

All the turbine governor parameters for the equivalent are known except:

T^*_R , D^* , T^*_F , C^*_D , K^*_I and K^*_P

These parameters are estimated using the parameter estimation program to match the aggregated transfer function with the equivalent transfer function.

Non Linear Parameters

The maximum generation limit for the equivalent model is calculated as the sum of the individual generation limit. The minimum generation limit is also calculated in the same manner.

The auxiliary gain function AUX represents the output capability of the boiler auxiliaries due to changes in voltage and frequency. The gain functions are represented by the expression [26]

$$AUX = f - f \cdot K_{AUX} (1 - V)^2$$

where

f is the normalized frequency

V is the normalized voltage

The parameter K_{AUX} can be estimated by aggregating individual auxiliary gain function and then matching the aggregated and equivalent gain function to give a minimal error.

2.2.6 Synchronous Machine and Excitation Models

The open loop transfer function for the synchronous machine and excitation system model is i_T/V_T.

In Figure 2.6 these entities are separately represented. The key assumption that the machines are on the same bus permits one to consider the transfer function between the terminal current and the terminal voltage, which is linear. The block diagram of Figure 2.6 applies to both the individual and the equivalent machine.

When both classical and detailed models belong to a coherent group, the classical models (without excitation control) are aggregated to form an equivalent classical unit and the detailed models are separately aggregated to form an equivalent detailed unit.

The equivalent is formed in two steps. First, the transfer function is aggregated without the excitation input. This provides the parameters of the equivalent synchronous machine.

Then the equivalent of the excitation system is formed. Since the output of the individual excitation systems are applied to synchronous machines that have different characteristics, it is necessary to weigh those outputs to form the equivalent field voltage.

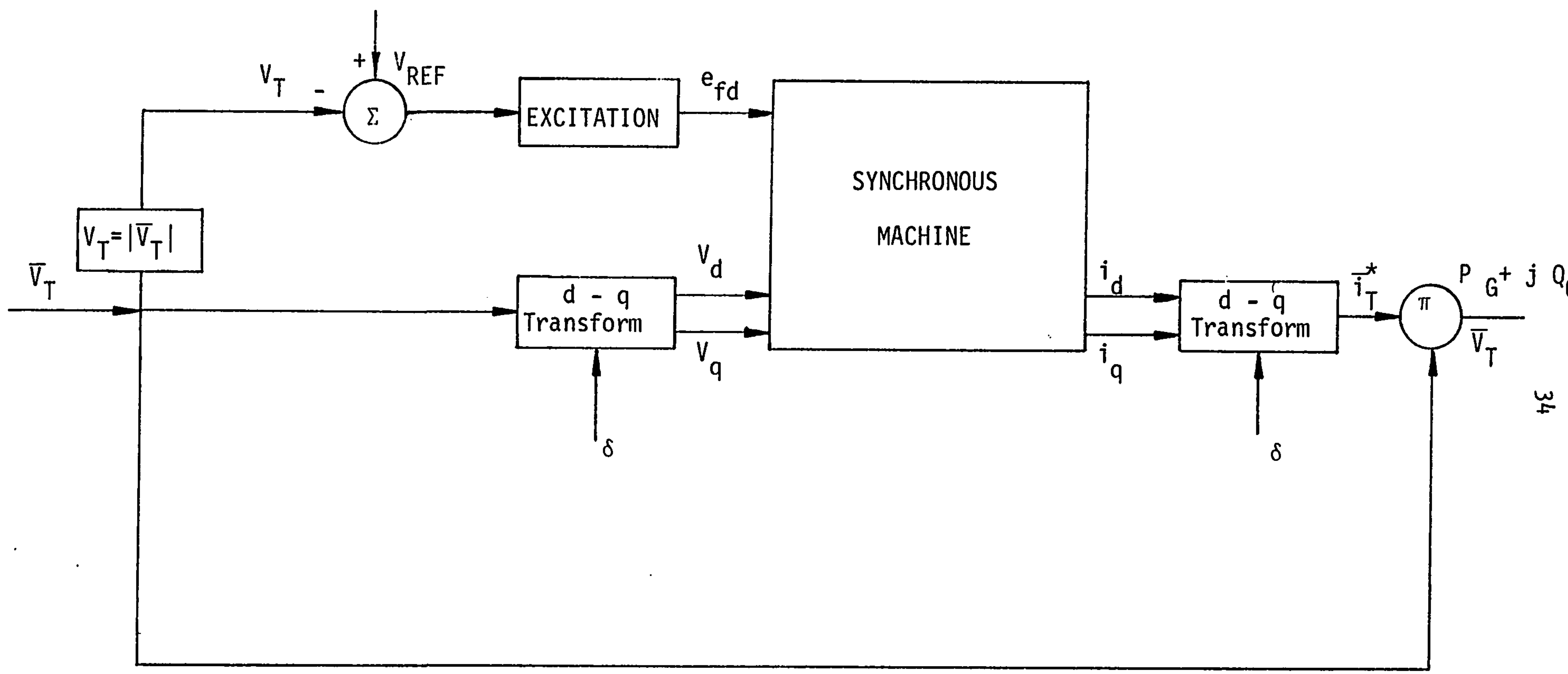


Figure 2.6 Synchronous Machine and Excitation System Model.

The coherent groups may be constituted of combinations of the following models:

Synchronous Machines

The two axis model with one field winding in the direct axis and one damping winding in the quadrature axis is used for each individual machine (Figure A-1). The round rotor machine and classical model are considered as a special cases. The transient of the stator are neglected.

Excitation Systems

Four different models of rotating and static excitation system are represented [19,20], for simplicity sake all the machines have IEEE type I excitation system model.

2.2.7 Formation of the Equivalent Synchronous Machine

Assuming coherency:

- The difference of rotor angles between machines of a coherent group remain constant.

- The terminal voltages are the same for each machine of the group, since they are connected in parallel on the same bus after reduction of the coherent buses.

These assumptions are used to demonstrate in Appendix A that a dynamic equivalent can also be represented as a two axis model. The justification is the equivalence of the electromagnetic power output.

The total electromagnetic power output P_G of the coherent group is:

$$P_G = \sum_j (V_{qj} i_{qj} + V_{dj} i_{dj}) \qquad (2.20)$$

with the terminal voltage and the stator current expressed for each machine in its own, reference axes, denoted by the subscripts d and q. Since the terminal voltage is common, the total electric power is expressed as:

$$P_G = V_Q \Sigma i_{Qj} + V_D \Sigma i_{Dj} \qquad (2.21)$$

where subscripts D and Q represent components on an arbitrary pair of orthogonal axes.

It is shown in Appendix A that Σi_D and Σi_Q are related to V_D and V_Q by the expression:

$$\begin{bmatrix} \Sigma i_D(s) \\ \Sigma i_Q(s) \end{bmatrix} = \begin{bmatrix} Y_{DD}(s) & Y_{DQ}(s) \\ Y_{QD}(s) & Y_{QQ}(s) \end{bmatrix} \begin{bmatrix} V_D \\ V_Q \end{bmatrix} + \begin{bmatrix} Y_{DF} \\ Y_{QF} \end{bmatrix} e_{FD} \qquad (2.22)$$

where $Y_{DD}(s)$, $Y_{DQ}(s)$, $Y_{QD}(s)$ and $Y_{QQ}(s)$ depend on the parameters of the individual machines and on the position of the axes D and Q and are defined in Appendix A.

The equivalent machine is a two-axes model as well, thus its electric power output is:

$$P_G^* = V_Q \cdot i_Q^* + V_D \, i_D^* \qquad (2.23)$$

with

$$\begin{bmatrix} i_D^* \\ i_Q^* \end{bmatrix} = \begin{bmatrix} 0 & Y_{DQ}^*(s) \\ Y_{QD}^*(s) & 0 \end{bmatrix} \begin{bmatrix} V_D \\ V_Q \end{bmatrix} + \begin{bmatrix} Y_{DF}^*(s) \\ 0 \end{bmatrix} e_{FD} \qquad (2.24)$$

The position of the equivalent axes and the parameters of the equivalent model are calculated to minimize the difference between the electric power output P_G^* of the equivalent and the total electric power output of the individual machine P_G.

The aggregation of the synchronous machine proceeds as follows (See Appendix A)

- o First the position of the axes is calculated, such that Y_{DD}, Y_{QQ}, and Y_{QF} in equation (2.22) are made negligibly small in the frequency range of concern.

- o Then the parameters of the equivalent model are adjusted separately for each axis by fitting the operational admittance Y^*_{DQ} with Y_{DQ} and Y^*_{QD} with Y_{QD}.

This is obtained by adjusting the parameters of the equivalent to fit its operational admittances to the operational admittances of the aggregated machines.

2.2.8 Aggregation of the Excitation System Models

Each individual excitation system is represented by a single-input single-output block diagram.

Ignoring the regulator limits, the linear transfer function of one exciter is $G_{Ej}(s)$.

The terminal voltage V_T is the common input to each exciter. Assuming this input small enough that none of the regulators reaches its limit, the output e_{fd} is expressed for each exciter as:

$$e_{fdj}(s) = G_{Ej}(s) \, . \, \Delta V_T(s) \qquad (2.25)$$

where $\Delta V_T = (V_{REF} - V_T)$ is the terminal voltage error.

The field voltages e_{fd}, applied to the individual synchronous machine models result in a contribution to the total current denoted as Δi_D (see Appendix A)

$$\Sigma \, \Delta i_{Dj}(s) = \Sigma \left(\frac{\Delta i_D(s)}{e_{fd}(s)} \; \frac{e_{fd}(s)}{\Delta V_T(s)} \right) \bullet \Delta V_T(s)$$

$$= \Sigma \, (Y_{dfj}(s) \, \text{Cos} \, \phi_j \; G_{Ej}(s) \, \Delta V_T(s) \qquad (2.26)$$

The transfer function

$$\frac{\Sigma \Delta i_{Dj}(s)}{\Delta V_T(s)} = \Sigma \, (Y_{dfj}(s) \bullet \text{Cos} \, \phi_j \bullet G_{Ej}(s)) \qquad (2.27)$$

has to be identified with the transfer function between the same variables in the equivalent models extracted from the equation (2.24):

$$\frac{\Delta i_D^*}{\Delta V_T} = Y^*_{DF}(s) \bullet \frac{\Delta e_{FD}(s)}{\Delta V_T(s)} \tag{2.28}$$

It is convenient to rewrite this condition as:

$$G_E^* = \frac{\Delta e_{FD}}{\Delta V_T} = \Sigma \left[\frac{Y_{dfj}(s)}{Y^*_{DF}(s)} \text{ Cos } \phi_j \right] \bullet G_{Ej}(s) \tag{2.29}$$

and consider the expression between brackets as a "weight-factor" $W_j(s)$ that accounts for the parameters of the synchronous machines to which the excitation systems are connected. This is represented in Figure 2.7.

At this stage, $Y^*_{DF}(s)$ is known from the parameters of the equivalent synchronous machine. The right-hand side of equation (2.29) can thus be calculated for discrete frequencies.

Equivalent Model

A model of IEEE Type 1 (Figure 2.8) with a transfer function $G^*_E(s)$ represents the equivalent. Ignoring the regulator limits, the parameter of this model are adjusted, using a gradient search to minimize the mean square of the error between $G^*_E(s)$ and the right-hand side of equation (2.29).

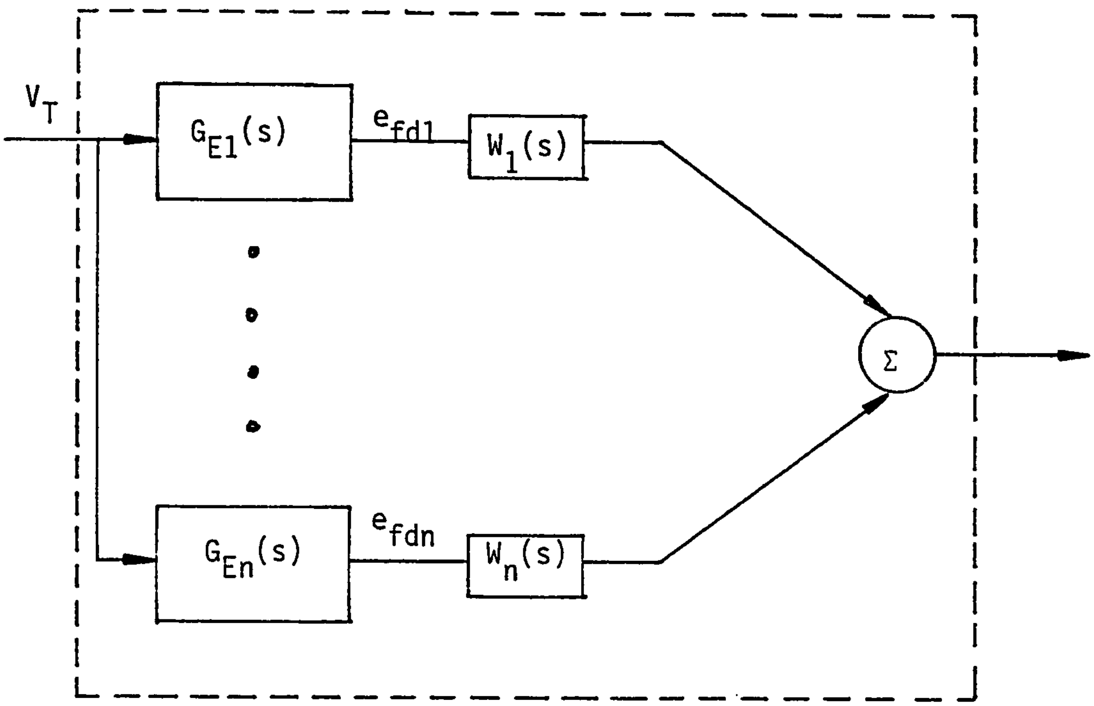


Figure 2.7 Formation of the equivalent field voltage by weighting the output of the individual excitation systems.

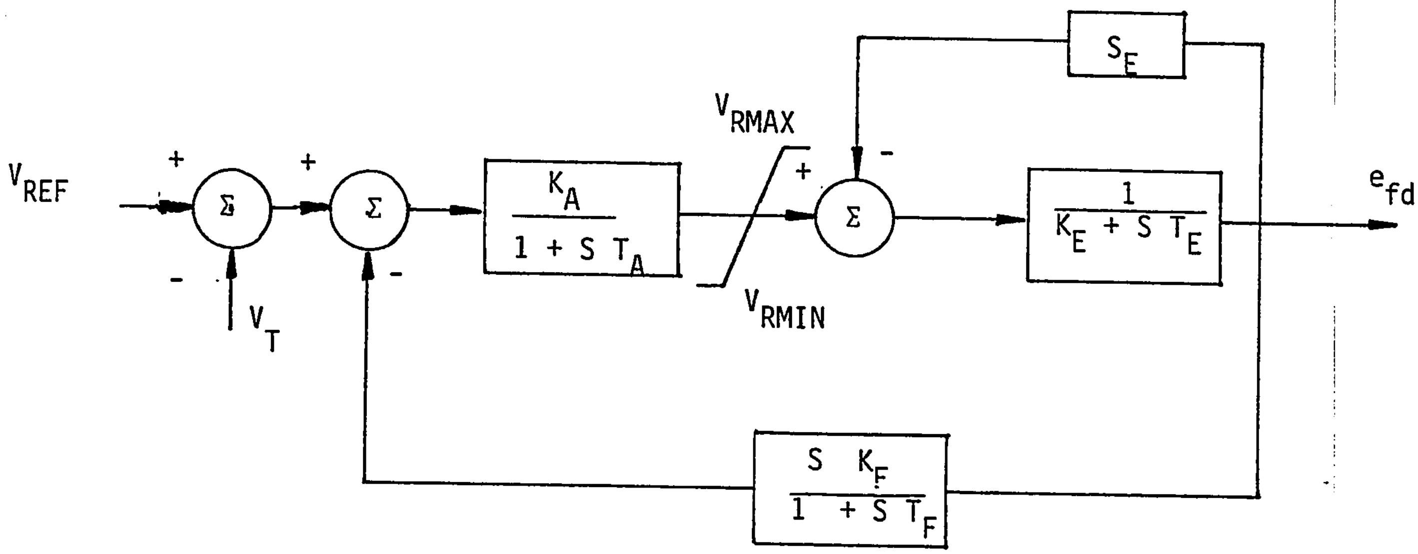


Figure 2.8 IEEE Type 1 Excitation System Model

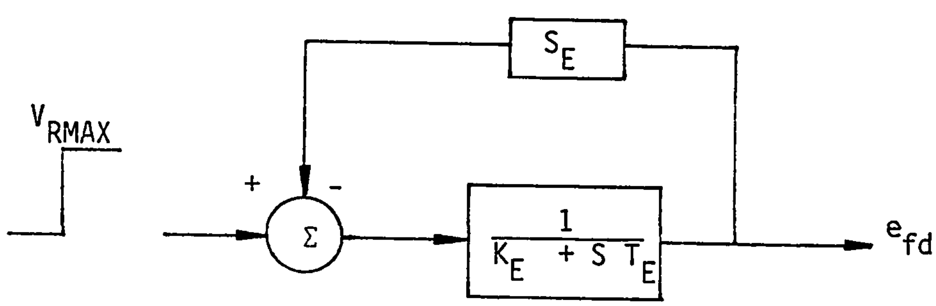


Figure 2.9 Simplified Exciter Model for Large Step Input.

Regulator Limits

The equivalent limits are calculated assuming that a step input equal to the regulator limit is applied simultaneously to each exciter system. For such a step input, the output is (Figure 2.9)

$$e_{FD}(s) = 1/S \sum_j \left(\frac{V_{RMAX}/(K_E+S_E)}{1+ST_{Ej}/(K_E+S_E)_j} \right) \bullet W_j(s) \qquad (2.30)$$

Using the initial and final value theorem [28]:

$$\underset{t\to 0+}{\text{O Lim}} \frac{de_{FD}}{dt} = \sum_j \frac{V_{RMAX}}{T_{Ej}} \bullet W_j(s{=}\infty) \qquad (2.31)$$

For the equivalent the same limit is V^*_{RMAX}/T^*_E since the parameters T^*_E is already known from the fitting the linear transfer function, this relation determines

$$V^*_{RMAX} = T^*_E \left(\sum_j \frac{V_{RMAXj}}{T_{Ej}} \bullet W_j\ (s{=}\infty)\right) \qquad (2.32)$$

Also,

$$\underset{t\to\infty}{\text{O Lim}}\ e_{FD}(t) = \sum_j \frac{V_{RMAXj}}{(K_E+S_E)_j} \bullet W_j(0) = E^*_{FDMAX} \qquad (2.33)$$

For the equivalent model, the same limit is:

$$\frac{V^*_{RMAX}}{(K_E + S_{EMAX})^*} = E^*_{FDMAX} \tag{2.34}$$

Since V^*_{RMAX} is already known (from 2.32), equation (2.33) provides E^*_{FDMAX} and (2.34) $(K_E + S_E)^*$.

In some instances, it occurs that the equivalent parameter T^*_E found by the estimation procedure is negligibly small. V^*_{RMAX}/T^*_E is not defined and in this case, the equivalent excitation system is considered as being a static excitation system model. Equations (2.32) and (2.34) do not apply, but (2.33) is used to calculate E^*_{FDMAX}.

Exciter Saturation Coefficient

Two discrete values of the saturation function $S_E(E_{fd})$ are given for each exciter, at E_{fd}MAX. An exponential relation is assumed for this function. The equivalent function is calculated at two points (initial operating point and E^*_{FDMAX}). It is assumed that this function is exponential as well.

2.3 PARAMETER ESTIMATION PROGRAM

The parameter estimation program first calculates the transfer function of each components of the individual power plant model for discrete complex frequencies and sums it up for all the coherent units. The result is the aggregated transfer function.

The equivalent transfer function is of the form

$$\hat{Y} = F(x_1, x_2, --- x_k; \hat{A}_1, \hat{A}_2, --- \hat{A}_M)$$

where $\hat{Y}$ is the equivalent transfer function

x_i are the frequency points

$\hat{A}_i$ are the unknown parameters.

The procedure used for least square estimation was proposed by Marquardt [18], this method can be used for poor starting values of the unknown coefficients. The algorithm proceeds as follows.

i) The model is linearized by expanding $\hat{Y}_i$ in a taylor series about current trial values for the coefficients and retaining the linear term only,

$$\hat{Y}_i = \hat{Y}_i^* + \left[\frac{\partial \hat{Y}_i}{\partial \hat{A}_1}\right]^* \Delta \hat{A}_1 + \left[\frac{\partial \hat{Y}_i}{\partial \hat{A}_2}\right]^* \Delta \hat{A}_2 + \text{-----}$$

$$+ \left[\frac{\partial \hat{Y}_i}{\partial \hat{A}_M}\right]^* \Delta \hat{A}_M$$

where $\Delta \hat{A}_j = [\hat{A}_j - \hat{A}_j^*]$, $j = 1, 2, \text{---} M$

The asterisk designates quantities evaluated at the initial trial values.

ii) A least square objective function is formulated,

$$\text{Minimize} \quad S = \sum_{i=1}^{N} (Y_i - \hat{Y}_i)^2$$

where

Y_i is the magnitude of the aggregated transfer function at i frequency point

$\hat{Y}_i$ is the magnitude of the equivalent transfer function at i frequency point.

iii) The linearized model is substituted into the objective function and the "Normal equations" formed by setting the partial derivatives of the objective function with respect to each coefficient equal to zero

$$\frac{\partial S}{\partial A_j} = 0 \qquad j = 1, 2, \text{----} M$$

The resulting normal equation is of the form

$$[\underline{A}^t \, \underline{A} + \lambda^* \underline{I}] \, \Delta \hat{\underline{A}} = \underline{A}^t \, (Y - \hat{Y}^*)$$

where $\underline{I}$ is identity matrix

λ is a factor

$$\underline{A} = \begin{bmatrix} \dfrac{\partial \hat{Y}_1}{\partial \hat{A}_1} & \dfrac{\partial \hat{Y}_1}{\partial \hat{A}_2} & \text{------} & \dfrac{\partial \hat{Y}_1}{\partial \hat{A}_M} \\ \vdots & \vdots & & \vdots \\ \dfrac{\partial \hat{Y}_N}{\partial \hat{A}_1} & \dfrac{\partial \hat{Y}_N}{\partial \hat{A}_2} & & \dfrac{\partial \hat{Y}_N}{\partial \hat{A}_M} \end{bmatrix}$$

$$\Delta\hat{\underline{A}} = \begin{bmatrix} (\hat{A}_1 - \hat{A}_1^*) \\ \\ \\ (\hat{A}_M - \hat{A}_M^*) \end{bmatrix} \qquad (Y-Y^*) = \begin{bmatrix} (Y_1 - \hat{Y}_1^*) \\ \\ \\ (Y_N - \hat{Y}_N^*) \end{bmatrix}$$

$\underline{A}^t$ is the transpose of $\underline{A}$ matrix.

iv) The normal equations are a system of linear algebraic equations and are solved for $\underline{\Delta A}$. If $\underline{\Delta A}$ vector and S will approach zero as convergence is achieved. If convergence is achieved, the final coefficients are calculated from

$$\hat{A}_j = \hat{A}_j^* + \Delta\hat{A}_j \; ; j = 1, 2, ---- M$$

If convergence is not achieved, A^*, is updated by replacing the old values by the new values and the process repeated.

A flow sheet illustrating the above procedure is given in Figure 2.10 and the source listing of the program is given in the Appendix C.

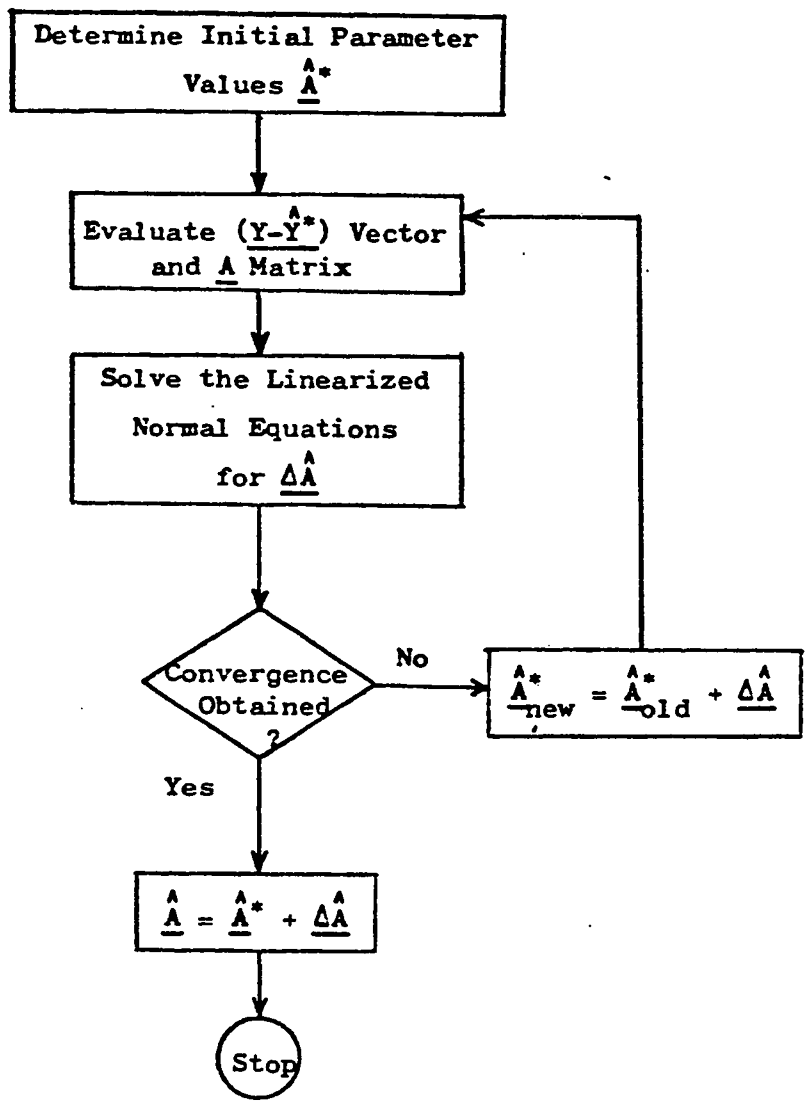


Figure 2.10 Least Square Estimation Algorithm Flow Chart

Chapter III

LONG TERM DYNAMIC SIMULATION PROGRAM

3.1 INTRODUCTION

The long term dynamic simulation program is a modified version of Podmore's power system dynamic simulation program [22], so as to include a detailed model of turbine, turbine control, boiler, boiler control and auxiliaries, in addition to the generator and excitation system model which were already present in the original simulation program.

The objective of this chapter is to describe the subroutine TRBL, which incorporates a detailed model of turbine and boiler systems. The details of the original program can be obtained from the Power System Dynamic Simulation Program User Manual [22].

The long term dynamic program requires the support of two others programs.

1. A power system load flow program.
2. A network reduction program.

The generators terminal condition and the reduced admittance matrix are given as the input data to the simulation program.

The source listing for the network reduction program is included in Appendix D.

3.2 OVERALL PROGRAM STRUCTURE

A flow diagram of the overall program is shown in Figure 3.1. The program is divided into the following subroutine:

- A main line routine which performs data initialization and input and which provides overall control of the program.

- The subroutine MATRIX addes each internal generator bus to the network admittance and then reduces the new matrix by eliminating the corresponding generator terminal bus.

- The network solution subroutine NWSOL calculates the terminal voltages and current from the generator internal voltages and rotor angle.

- A library of equipment subroutine GEN, AVR, TUR and TRBL for modelling the various types of generators, excitation system, turbine governor systems and a detailed turbine-

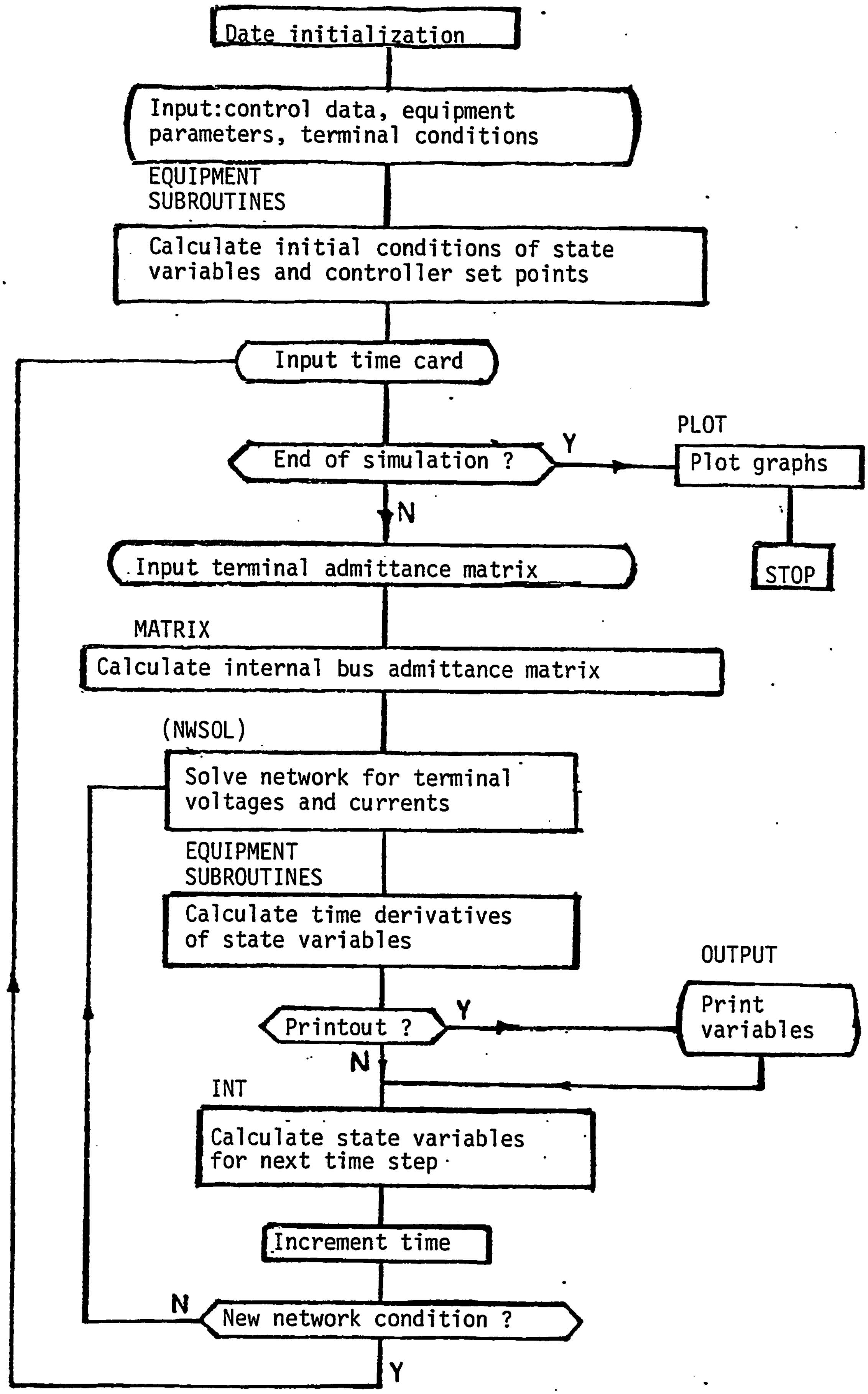


Figure 3.1 Long Term Dynamic Simulation Program Flow Diagram.

boiler systems respectively. Each equipment subroutine consists of two parts.

The first part calculates the initial conditions of the machine and controller state variables and the initial controller set points and is executed once at the start of the program.

The second part calculates the time deviations of the machine and controller state variables at each integration time step.

- o The integration subroutine INT calculates the state variables for a new time interval as a function of the state variables and state variable derivatives for the present and preceding intervals.

- o The subroutines OUTPUT and PLOT respectively give printouts and plots of the variables calculated during the simulation.

3.3 BOILER-TURBINE SPEED GOVERNING AND CONTROL MODEL [25, 26 & 27]

Simulation of long term power system dynamic requires a detailed modelling of energy sources and their controls, which are used in the equipment subroutine TRBL in the long term dynamic simulation program.

The model consists of four separate but interconnected components to represent the fossil-fired prime-mover. Which includes the following:

- o Governor/Turbine Control
- o Steam Turbine
- o Boiler Control and Auxiliaries
- o Boiler.

These components and the variables that connect them are shown schematically in Figure 3.2. Inputs include the Automatic Generation Control (AGC) power signal, generator electrical power and generator terminal voltage and frequency. The latter two items are used in the boiler model to calculate degradation of boiler performance due to bus voltage and/or frequency.

3.3.1 Turbine Control

The turbine-control includes the load reference motor, rate and position limit for the LRM, proportional plus integral controllers, least value gate, governor and its limits and the steam chest. Figure 3.3 shows the block diagram representation of a Type E turbine control model along with the turbine dynamic model and the boiler model.

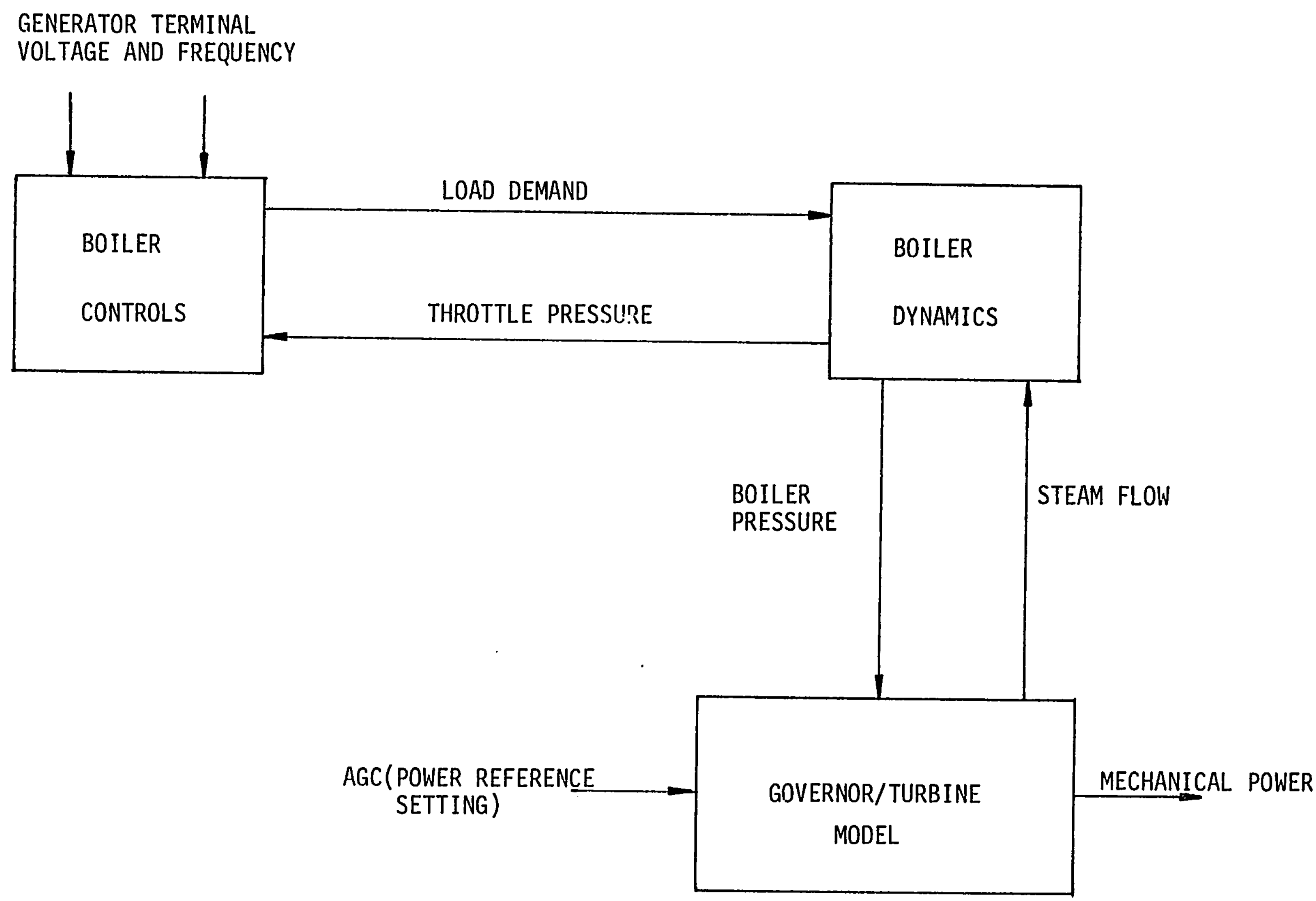


Figure 3.2 A Block Diagram Showing The Interface Between Boiler Model and Turbine/Governor Model.

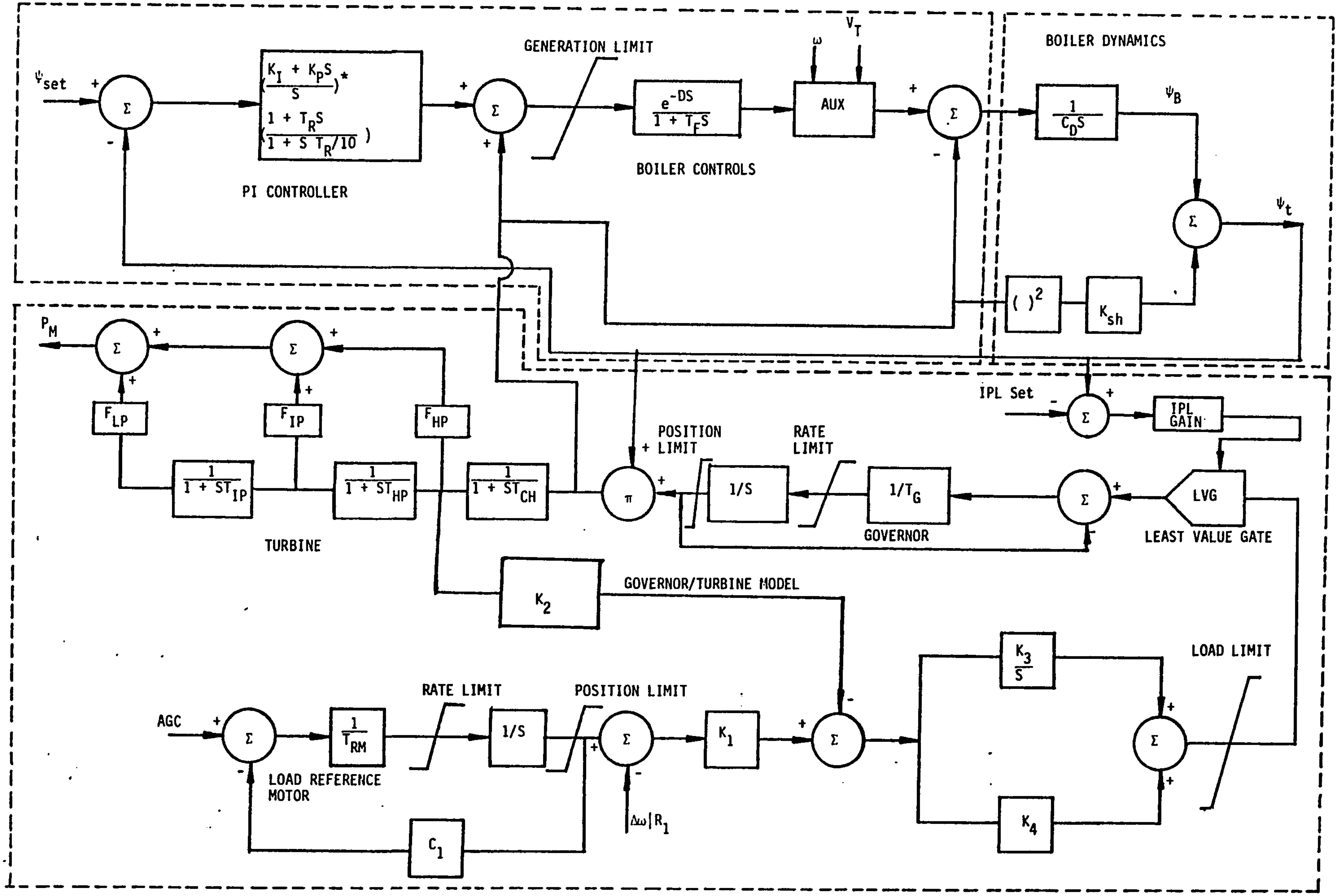


Figure 3.3 Boiler-Turbine Speed Governing and Control Model.

The input to the load reference motor (LRM), is the automatic generation control (AGC) signal. A feed back circuit through C_1 tracks the drive signal. The time constant associated with the LRM is TRM. The output of the LRM biased by frequency with a gain $1/R_1$ to obtained governor action.

The gain K_1 is a forward gain and K_2 is a feed back gain. K_3 and K_4 are the gains of a proportional plus integral controller. The output of the controller is limited by the function P_{MAX} to avoid wind up. The constant K_1 through K_4 are not independent. The overall gain is redundantly specified, so K_1 is always taken as unity. If K_3 is not zero, then K_2 must be unity so that the steady state input to the integrator is zero. If K_3 is zero, then

$$K_2 = I - I/K_4$$

and K_4 may not be zero.

The output of the load limiter is compared to the output of the initial pressure limiter (IPL) in the least value gate (LVG). The output of the LVG is the least of its two inputs, and is called control value demand. The function of the IPL is to close turbine control value when throttle pressure drops, to prevent the carry over of water into the turbine. The IPL is modeled by a simple set point and a gain.

The control valve demand biased by the valve area drives the speed governing system. Steam flow is calculated as the product of boiler throttle pressure and the effective flow capacity of the values.

3.3.2 Turbine Dynamics

The input to the steam turbine is the steam flow, and the output is the mechanical power. Almost all the turbines use governor controlled valve at their input to regulate the steam flow in the turbine.

The steam chest, inlet piping to the first turbine cylinder and reheater and crossovers piping downstream all introduces delays between valve movement and change in steam flow.

The tandem compound single reheat turbine is used in the subroutine TRBL, Figure 3.3 shows the block diagram of the turbine along with the turbine control and the boiler model.

3.3.3 Boiler Control and Auxiliaries

Boiler controls include a pressure loop, fuel and air delay, auxiliaries etc. Figure 3.3 shows a block diagrammatic representation of a type 'E' boiler control interfaced with boiler, turbine and turbine control.

The pressure controller consists of a proportional-integral controller (i.e. K_I and K_P gains) followed by a lead network. The controller operates on a pressure error signal that includes the difference between throttle pressure Ψ_{TH} and its set point (1.0).

The output of the pressure controller is summed up with the steam flow, produces the MW demand. This MW demand is then limited by a generation limit to protect the boiler.

The fuel/air dynamics are represented by a simple lag $\frac{I}{I + T_{FS}}$ and a time delay e^{-DS} to represent the transport time of coal feeders. For an oil or natural gas fired boiler, this delay might be negligible. If the delay D is small compared to the linear lag, T_F, then D is simply added to T_F. This may be done if $D \leq 20\ T_F$.

The gain, AUX, is inserted in the fuel/air path to account for the effect of low voltage and frequency on auxiliaries. The gain varies between zero and one. The gain falls to zero abruptly when a minimum threshold of filtered voltage or frequency is reached at which point the unit is tripped off.

Typical values [26] of this gain function for normalized values of voltage and frequency is given in Table I.

TABLE I. Fuel/Air Auxiliary Gain Function.

POLYNOMIAL APPROXIMATION OF GAIN FUNCTION

$$AUX = f - 4.024 f (I - V)^2$$

f NORMALIZED FREQUENCY	V-NORMALIZED VOLTAGE							
	1.000	0.959	0.897	0.875	0.859	0.830	0.769	0.761
1.000	1.000	0.993	0.957	0.937	0.920	0.884	0.833	0.000
0.990	0.990	0.983	0.948	0.928	0.911	0.875	0.824	0.000
0.973	0.973	0.966	0.931	0.912	0.895	0.860	0.810	0.000
0.957	0.957	0.951	0.916	0.897	0.880	0.849	0.797	0.000
0.938	0.938	0.932	0.898	0.879	0.863	0.829	0.781	0.000
0.918	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

The use of this tabulated function on a large number of units would use excessive memory. A polynomial fit to these linear data results in a polynomial approximation for the auxiliary gain function and is given as below:

$$AUX = f - f\,K_{AUX}\,(I - V)^2$$

Table XII shows the auxiliary gain when K_{AUX} = 4.024, V_{min} = 0.761 and f_{min} = 0.918.

3.3.4 Boiler

Figure 3.3 shows the boiler interfaced with boiler control and governor/turbine model. The input to the boiler model is the boiler charging from the boiler control. The error signal which is boiler charging biased by the steam flow is the input to an integrator with delay C_D, which represents the delay of thermal storage. The output of the integrator is the boiler pressure. The throttle pressure is obtained by subtracting the product of squared steam flow and super heater frictional drop coefficient K_{SH} from the boiler pressure.

3.4 GOVERNOR/TURBINE AND BOILER SUBROUTINE

The subrouting TRBL solves the dynamic equation of governor/turbine and boiler models, it performs two functions as follows:

- o Calculates the initial condition of the governor/turbine and boiler model state variables

- o Calculates the time derivative of the governor/turbine and boiler model state variable at each integration time step

A block diagram representation of the boiler-turbine speed governing and control model is shown in Figure 3.3. The subroutine TRBL was developed from the block diagram by following the modelling procedure explained in section 3.3.

The input variable to the subroutine TRBL is angular frequency ω which is the output of the integration subroutine INT and the output variable is the mechanical power P_M which is given as the input to the generator subroutine.

The listing of the subrouting TRBL along with the source listing of the long term dynamic simulation program is given in the Appendix E.

Chapter IV

TEST RESULTS

4.1 INTRODUCTION

The dynamic aggregation procedure developed in chapter II for the aggregation of power plant model is evaluated by comparing time responses of the equivalent with the responses of the full system, when the same disturbance is applied.

The dynamic equivalencing procedure includes the identification of coherent generators and the reduction of load and coherent generator buses along with the dynamic aggregation of the power plant model. The identification of coherent generator can be done by any of the methods reported in literature [10-15], however in this thesis the identification of coherent generators was done by comparing swing curve obtained by simulation of the full system, the reduction of the load buses was done using the well known Gaussian elimination procedure, computer program for reduction of load buses is given in Appendix D. The reduction of the coherent generator buses was done using a technique suggested in the EPRI report [17] (see Appendix B).

Two test systems have been used for evaluating the aggregation procedure:

- Three machine, infinite bus system (Fig. 4.1),

- New England system, 39 buses, 10 generators and 46 branches. This system is typical and represents the 345 KV system of the New England area.

4.2 AGGREGATION OF A THREE MACHINE SYSTEM

A group of three machine supposedly coherent machines, connected to an infinite bus through a transmission line was selected, the three coherent machines are to be aggregated using the technique described in this chapter.

4.2.1 Aggregation of Governor-Turbine Model

A type 'E' steam governor model (Figure 2.3) is used for all the three units. Tandem compound single reheat turbine (Figure 2.4) is used for units 1 and 3 and a nonreheat turbine is used for unit 2, the nonreheat turbine can be taken as a special case of single reheat turbine.

The aggregation of governor turbine model was done in the following steps.

First, the steady state parameter of the governor-turbine model are estimated as shown in section 2.2.3. Then using the parameter estimation

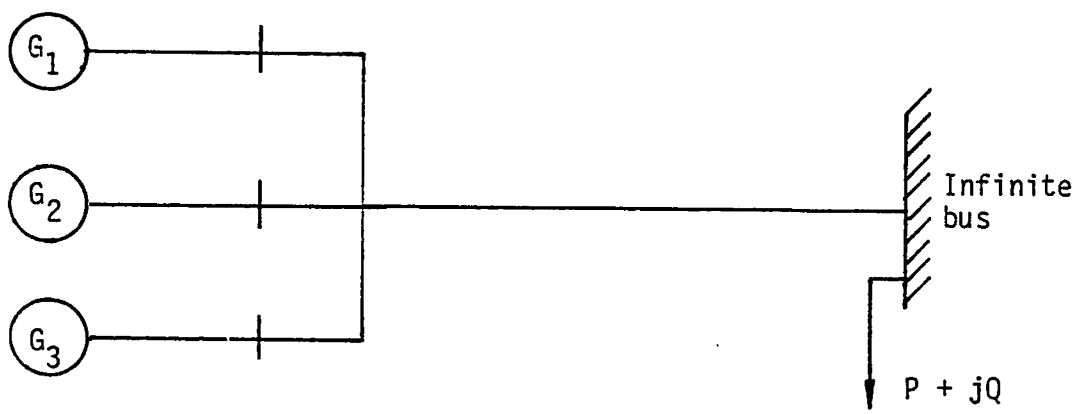


Figure 4.1 3 Generator Infinite Bus Test System

program the dynamic parameters of the governor turbine models are identified assuming all the units are operating at 70% of its maximum output power. Lastly the non linear parameter and limits are calculated.

The parameters of individual and equivalent governor are given in Table II and the parameters of individual and equivalent turbine are given in Table III.

4.2.2 Aggregation of Boiler Model

A drum type boiler model (Figure 2.5) is used for all the three units. The three units are assumed to be operating at 70% of their maximum capacity.

The estimation of the "boiler" linear parameters is done using the parameter estimation program. The maximum and minimum generation limits are then calculated for the equivalent boiler.

The auxiliary gain function will be the same as that of individual boiler, as they all equal for the individual units.

The parameters of the individual and equivalent boiler model are given in Table IV.

TABLE II. Parameter of Individual and Equivalent Governor.

Power Plant Unit	K_1	K_2	K_3	K_4	T_G	R_1	IPL GAIN	P_{MAX}	CV_{MAX}	CV_{MAX}	CV_{MIN}
1	1.0	0	0	1.0	0.45	0.05	10.0	1.0	1.0	0.025	-0.025
2	1.0	0	0	1.0	0.3	0.05	10.0	1.0	1.0	0.025	-0.025
3	1.0	0	0	1.0	0.464	0.05	10.0	1.0	1.0	0.025	-0.025
Equivalent	1.0	0	0	1.0	0.3476	0.05	10.0	1.0	1.0	0.025	-0.025

TABLE III. Parameters of Individual and Equivalent Turbine.

Power Plant Unit	F_{HP}	F_{IP}	F_{LP}	T_{CH}	T_{HP}	T_{IP}
1	0.3	0.25	0.45	0.4	10.5	6.0
2	0.35	0.0	0.65	0.403	0.0	7.0
3	0.3	0.25	0.45	0.45	8.0	4.0
Equivalent	0.31	0.202	0.488	0.4998	4.8098	8.8269

TABLE IV. Parameter of Individual and Equivalent Boiler Model.

Power Plant Unit	K_P	K_I	T_F	T_R	D	C_D	K_{sh}	K_{AUX}	GL MAX	GL MIN
1	4.0	0.04	7.0	8.0	6.0	145.0	0.08	4.024	1.0	0.2
2	5.0	0.05	5.0	6.0	8.0	125.0	0.08	4.024	1.0	0.2
3	3.3	0.045	5.0	6.0	8.0	165.0	0.08	4.024	1.0	0.2
Equivalent	3.78356	0.04337	5.3899	8.0	8.0	152.4442	0.08	4.024	1.0	0.2

4.2.3 Aggregation of Synchronous Machine

The two-axis model with one field winding in the direct axis and one damping winding in the quadrature axis is used for each individual machine. The transient of the stator are neglected. The same model is selected for the equivalent machine.

The aggregation is done as follows:

First, the position of the common pair of axis D and Q is calculated, such that the operation admittance Y_{DD}, Y_{QQ}, and Y_{QF} in equation (2.22) are made negligibly small in the frequency range of concern. Then, the parameters of the equivalent synchronous machine are identified using the parameter estimation program by adjusting separately for each axis by fitting the operational admittance Y^*_{DQ} with Y_{DQ} and Y^*_{QD} with Y_{QD}.

Lastly the saturation coefficient are calculated.

The parameter for individual and equivalent machines are given in the Table V.

TABLE V. Parameter of Individual and Equivalent Synchronous Machine.

(All Parameters on Machine Rating Base).

Power Plant Unit	X_d	X'_d	T'_{do}	X_q	X'_q	T'_{qo}	X_L	$S_{1.0}$	$S_{1.2}$	H	D
1	1.7	0.256	4.8	1.62	0.245	0.5	0.155	0.125	0.450	4.13	2.0
2	1.7	0.245	5.9	1.64	0.38	0.54	0.11	0.1251	0.7419	3.96	2.0
3	1.7668	0.2738	5.432	1.749	1.0104	1.5	0.1834	0.2632	0.5351	3.7	2.0
Equivalent	1.0422	0.168	4.7569	0.8471	0.2421	0.3181	0.0202	0.1711	0.577	3.88	2.0

4.2.4 Aggregation of Excitation System Model

The IEEE type I excitation system model is used for both the individual as well as the equivalent units. The aggregation of the Excitation system proceeds as follows: First the steady state parameters are estimated by substituting S = j0 along the imaginary axis. Then the rest of the linear parameters are estimated using the parameter estimation program. Lastly, the limits are calculated assuming that a step input equal to the regulator limit is applied simultaneously to each exciter system.

The parameter for individual and equivalent machines are given in Table VI.

4.3 SENSITIVITY STUDIES

Three types of sensitivity studies were done to see the effect on parameters values of the equivalent turbine, governor and boiler models, they are as follows:

- Effect of operating point on equivalent parameter values.
- Effect of decomposition of full model into subsystem on parameters value.
- Effect of variation in power plant parameters of individual units on estimated values and error.

TABLE VI. Parameter of Individual and Equivalent Excitation System.

Power Plant Unit	K_A	T_A	V_{RMAX}	V_{RMIN}	K_E	T_E	S_{75}	S_{MAX}	E_{FDMAX}	K_F	T_F
1	25	0.2	1.0	-1.0	0	0.605	0.083	0.323	3.72	0.096	1.0
2	25	0.2	1.0	-1.0	0	0.605	0.083	0.323	3.72	0.096	1.0
3	245	0.05	1.0	-1.0	0	1.37	0.22	0.95	3.57	0.04	1.0
Equivalent	56.3393	0.08423	1.46466	-1.46466	0	1.34666	0.128667	0.67259	1.9979	0.08334	1.031151

4.3.1 Effect of Operating Point on Parameter Values

The linear transfer function of the governor-turbine model (equation 2.9) and the governor-turbine and boiler model (equation 2.18) are a function of the operating point.

In order to check the sensitivity of the operating point on the equivalent parameter value, the equivalent parameter for governor, turbine and boiler were estimated for three different operating points.

Table VII gives the equivalent turbine-governor parameters with three different operating points and the sum square error between the aggregated transfer function and the equivalent transfer function, it is obvious from the table that the effect of operating point on the equivalent parameters of governor and turbine models is negligible and the sum square error is of the same order.

Similarly Table VIII gives the equivalent parameters of the boiler model with three different operating points and the sum square error between the aggregated transfer function and equivalent transfer function, it is observed that the effect of the operating point on the parameter of the equivalent boiler is negligible and the sum square error is of the same order for all the operating points.

TABLE VII. Parameters of Equivalent Governor-Turbine Model with the Variation in Operating Point and Model Decomposition.

Power Plant Unit/Output Power 1	2	3	Transfer Function	T_G	T_{CH}	T_{HP}	T_{IP}	Sum Square Error
0.7	0.7	0.7	$\frac{\Delta P_M}{\Delta\omega}$	0.34763	0.49985	4.80984	8.82687	0.26974
0.4	0.4	0.4	$\frac{\Delta P_M}{\Delta\omega}$	0.34756	0.4999	4.8098	8.82648	0.26726
0.9	0.6	0.6	$\frac{\Delta P_M}{\Delta\omega}$	0.3442	0.5046	4.79114	8.81224	0.33588
0.7	0.7	0.7	$\frac{\Delta m}{\Delta\omega}$	0.42366	-	-	-	21.538
0.7	0.7	0.7	$\frac{\Delta P_M}{\Delta\omega}$	-	0.42242	4.85045	8.7482	1.163059

TABLE VIII. Parameters of Equivalent Boiler Model with Variation in Operating Point and Model Decomposition.

Power Plant Unit/Output Power 1	2	3	Transfer Function	D	T_F	C_D	T_R	K_P	K_I	Sum Square Error
0.7	0.7	0.7	$\frac{\Delta P_M}{\Delta\omega}$	8.0	5.3899	152.444	8.0	3.7836	0.04337	2.29316
0.4	0.4	0.4	$\frac{\Delta P_M}{\Delta\omega}$	8.0	5.7793	150.9859	8.0	3.8284	0.04263	1.14482
0.9	0.6	0.6	$\frac{\Delta P_M}{\Delta\omega}$	8.0	5.8511	158.7052	8.0	3.9379	0.04359	1.54464
0.7	0.7	0.7	$\frac{\Delta m}{\Delta\omega}$	7.4474	5.54137	147.9873	7.9682	3.6884	0.042622	2.41018×10^3

4.3.2 Effect of Model Decomposition on Parameter Values

The governor-turbine model was decomposed into the governor model and the transfer function $\Delta m(s)/\Delta\omega(s)$ (equation 2.7) was aggregated first to estimate the parameters of the governor model, then the full governor-turbine transfer function (equation 2.9) was aggregated to identify the turbine parameters.

The effect of decomposition of model is shown in Table VII, it can be seen that there is little change in the equivalent parameter of the governor and turbine model but the sum square error between the equivalent and aggregated transfer function is much higher when the transfer function $\Delta m(s)/\Delta\omega(s)$ is aggregated.

The model decomposition was also carried out while estimating the boiler parameter, in this case only the governor-boiler transfer function $\Delta m(s)/\Delta\omega(s)$ (equation 2.16) was aggregated to identify the equivalent boiler parameters, the effect of decomposition can be seen from Table VIII, the equivalent parameters estimated shows a little variation from the full model case, but the sum square error between the aggregated and equivalent transfer function in the case of decomposed model is much higher than that obtained by a full model.

4.3.3 Effect of Variation in Power Plant Parameter on Estimated Values and Error

To observe the effect of variation of parameters on the equivalent parameter values and the sum square error between the equivalent and the aggregated transfer function.

The governor-turbine parameters for unit 1 are changed by a little amount (Table X) and the equivalent governor-turbine parameter and evaluated by the parameter estimation program. It can be seen from Tables IX and X that a little change in the governor-turbine parameter value for unit 1 does not have a significant effect on the values of the equivalent governor turbine parameters. The sum square error between the equivalent and aggregated transfer function is also of the same order.

Similarly for a little change in boiler parameter value for unit 1 (Table XII), the equivalent boiler parameter are estimated.

The result of the parameter estimation program shows that the effect of little change of the boiler parameter of unit 1 is not much (Tables XI and XII) and the sum square error between the equivalent and aggregated transfer function is of the same order.

TABLE IX. Parameters of Individual and Equivalent Governor/ Turbine Model.

Power Plant Unit	T_G	T_{CH}	T_{HP}	T_{IP}	Sum Square Error
1	0.45	0.4	10.5	6.0	-
2	0.3	0.403	0	7.0	-
3	0.464	0.45	8.0	4.0	-
Equivalent	0.3476	0.49985	4.8098	8.8269	0.26974

TABLE X. Parameters of Individual and Equivalent Governor Turbine Model with Variation in Parameter of Unit 1.

Power Plant Unit	T_G	T_{CH}	T_{HP}	T_{IP}	Sum Square Error
1	0.42	0.35	9.0	5.0	–
2	0.3	0.403	0	7.0	–
3	0.464	0.45	8.0	4.0	–
Equivalent	0.33039	0.49194	4.7216	8.0499	0.107964

TABLE XI. Parameters of Individual and Equivalent Boiler Model.

Power Plant Unit	D	T_F	C_D	T_R	K_P	K_I	Sum Square Error
1	6.0	7.0	145.0	8.0	4.0	0.04	-
2	8.0	5.0	125.0	6.0	5.0	0.05	-
3	8.0	5.0	165.	06.0	3.3	0.045	-
Equivalent	8.0	5.3899	152.444	8.0	3.7836	0.04337	2.29316

TABLE XII. Parameters of Individual and Equivalent Boiler Model with Variation in Parameter of Unit 1.

Power Plant Unit	D	T_F	C_D	T_R	K_P	K_I	Sum Square Error
1	6.5	7.5	150.0	8.5	4.5	0.045	-
2	8.0	5.0	125.0	6.0	5.0	0.05	-
3	8.0	5.0	165.0	6.0	3.3	0.045	-
Equivalent	8.0	5.35	147.219	8.0	3.7609	0.04291	2.51387

4.4 VALIDATION TEST FOR A THREE-MACHINE SYSTEM

The objective of this test was to verify that the assumption and the criteria of fitting transfer functions were meaningful and to assess the difficulties encountered in applying the method.

The three coherent units are aggregated using the technique described in chapter II, the result of aggregation are given in section 4.2. To complete the equivalencing procedure, the coherent generator buses were reduced using the technique explained in Appendix B and the load buses were reduced using the network reduction program (Appendix D).

The disturbance was a 20% load increase at the infinite bus.

Two cases were considered:

In case 1, all the three power plant units were operating at 0.6 of their rated power, using the long term dynamic simulation program, the same fault was simulated for individual power plant models, and again with the equivalent power plant model.

The frequency, total mechanical power, boiler pressure and mechanical power are plotted in Figs. 4.2 through 4.5 for both individual units and equivalent.

In case 2, the three individual power plant units are operating at different power output, using the long term dynamic simulation program, the same fault was simulated for individual power plant models, and again with the equivalent power plant model.

The terminal voltage, total mechanical power, electrical power, steam flow, throttle pressure and boiler pressure are plotted in Figs. 4.6 through 4.11 for both individual units and equivalent.

There is a good agreement between the total mechanical power output and frequency obtained with the individual models and with the equivalents.

4.5 VALIDATION TEST FOR A 39 BUS NEW ENGLAND SYSTEM

The objective of this test was to evaluate the performance of the coherent power plant units. The evaluation is done by comparing the time response of the equivalent with that of the full system.

The test system has 39 buses, 46 branches, 10 generators and 12 off-nominal transformers. This system is typical and represents the 345 kV system of New England area; but, since it is intended as a basis of comparison of equivalent system with the full system, no attempt was made to have it exactly reproduced any specific system operating conditions.

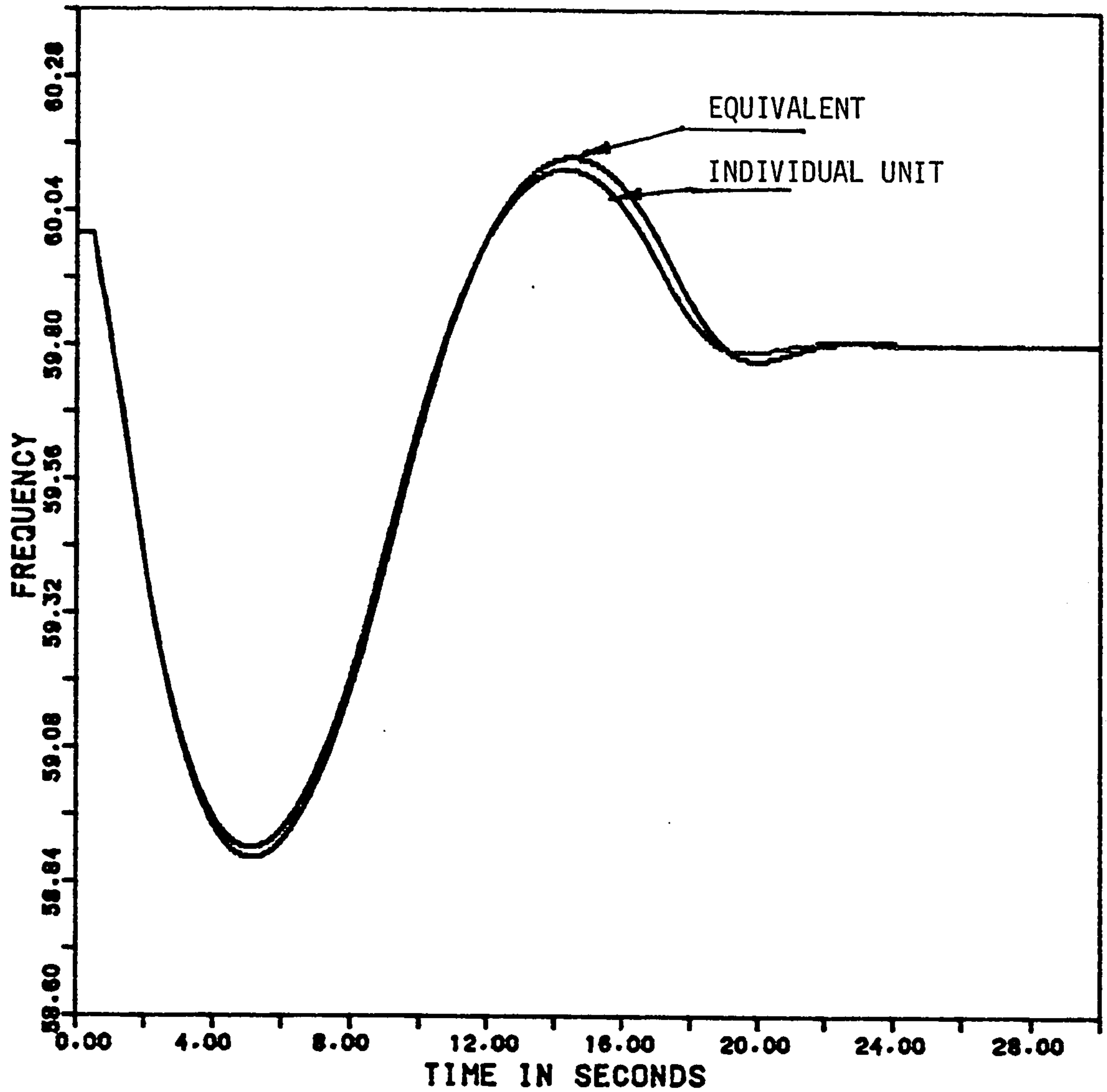


Figure 4.2 3 Machine System Case 1: Frequency of individual and Equivalent Power Plant Units.

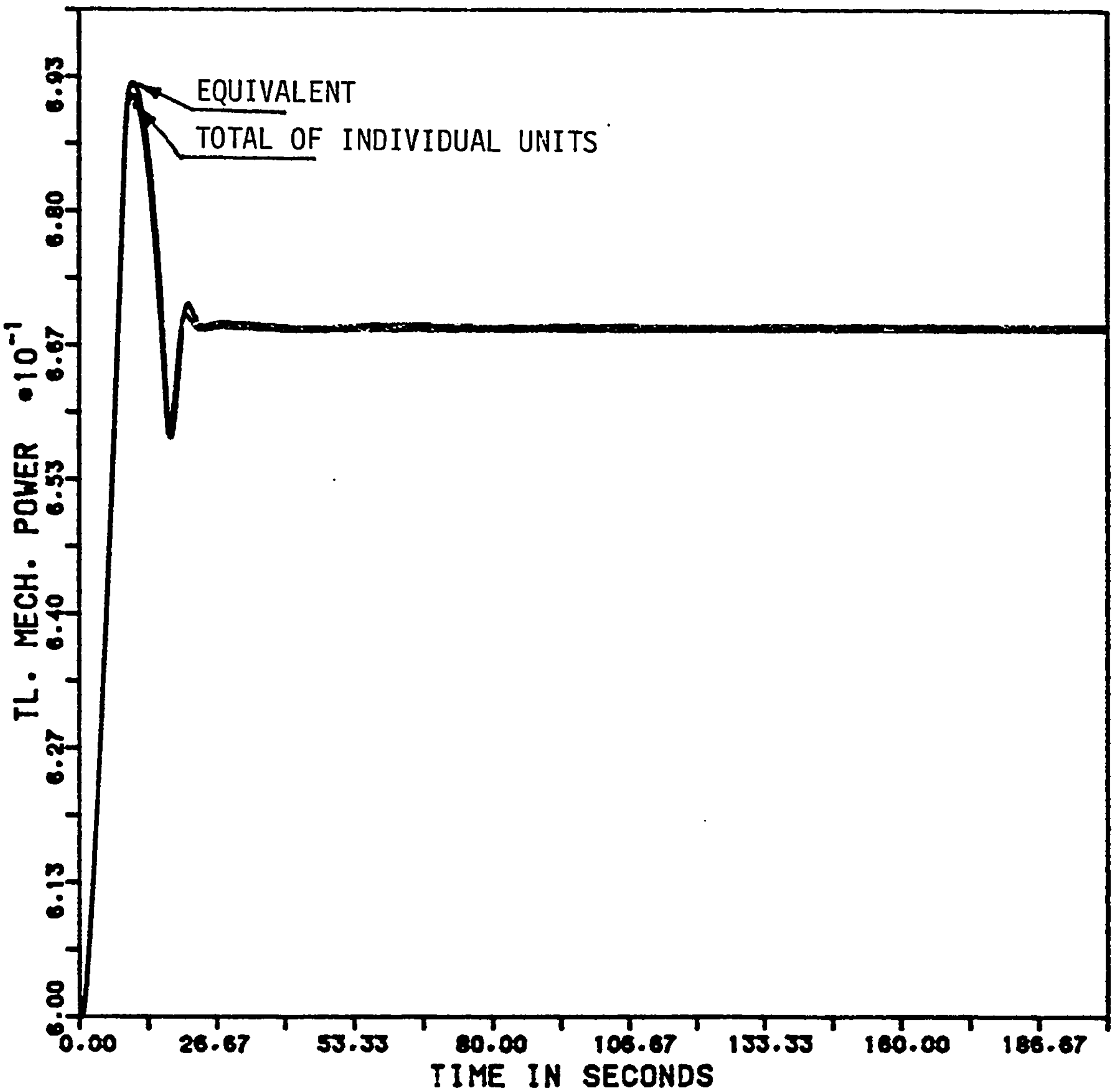


Figure 4.3 3 Machine System, Case 1: Total Mechanical Power Output of the Individual Power Plant Units and Mechanical Power Output of the Equivalent.

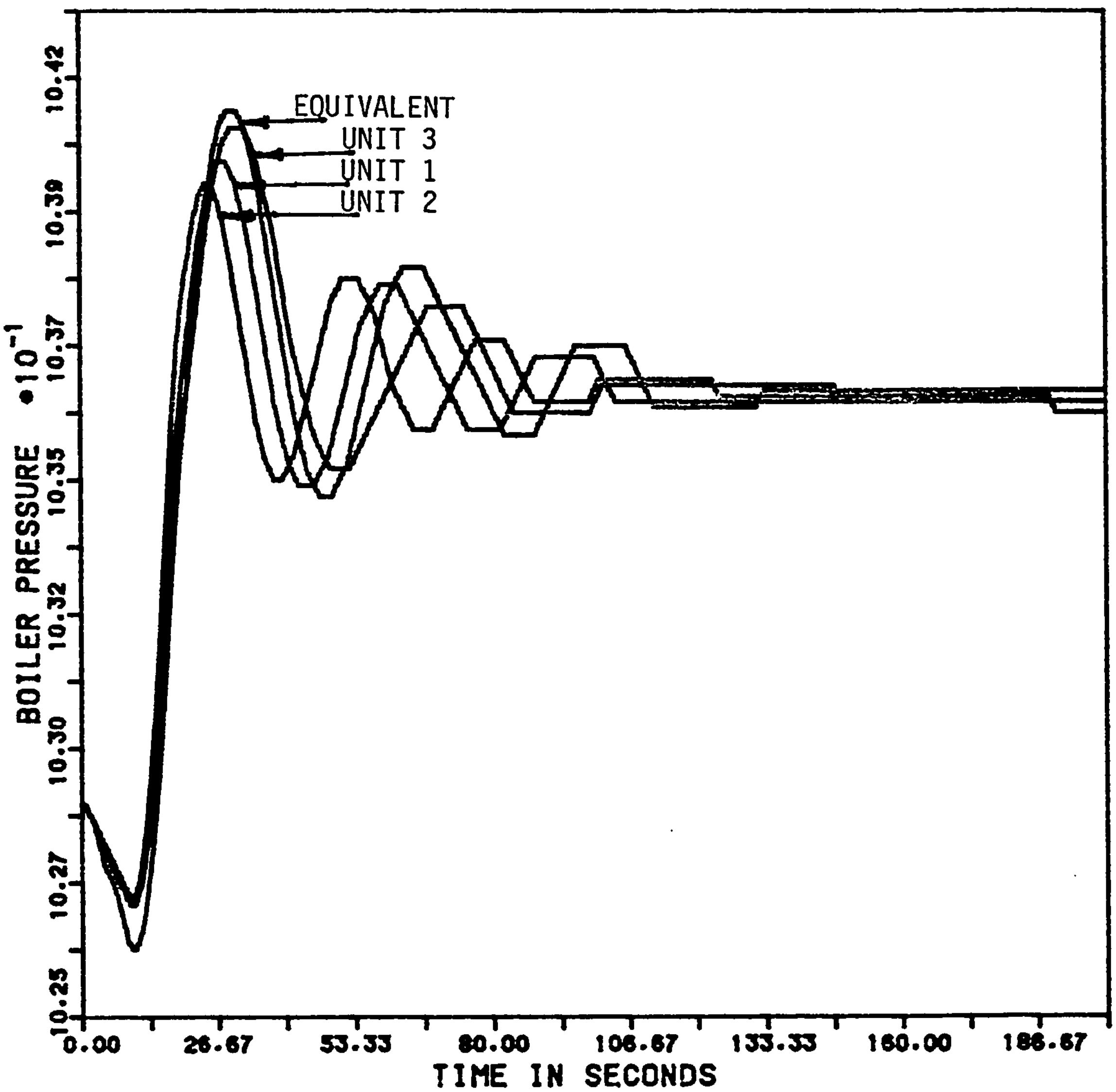


Figure 4.4 3 Machine System Case 1 : Boiler Pressure of Individual and Equivalent Power Plant Units.

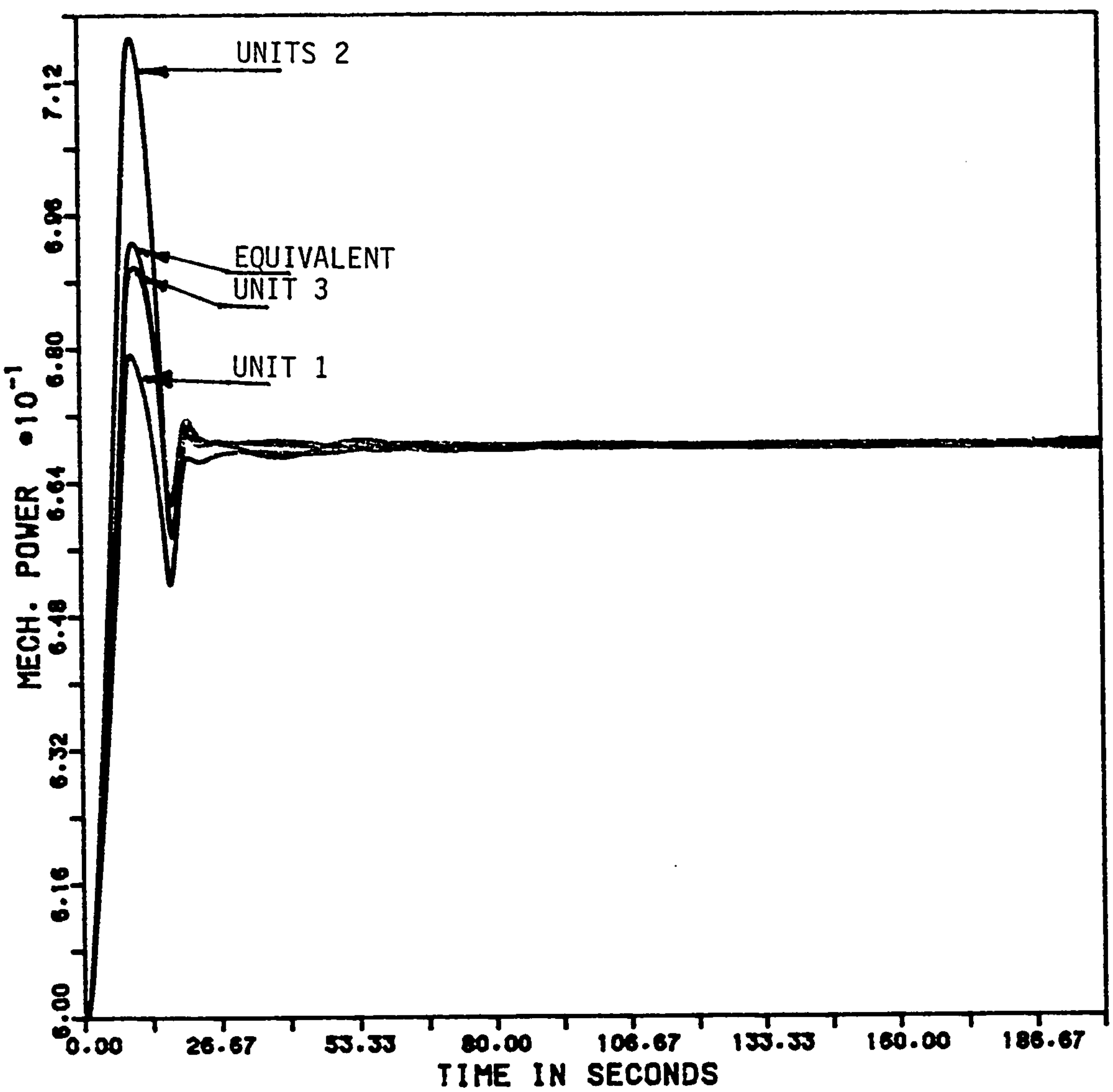


Figure 4.5 3 Machine System Case 1: Mechanical Power of Individual and Equivalent Power Plant Units.

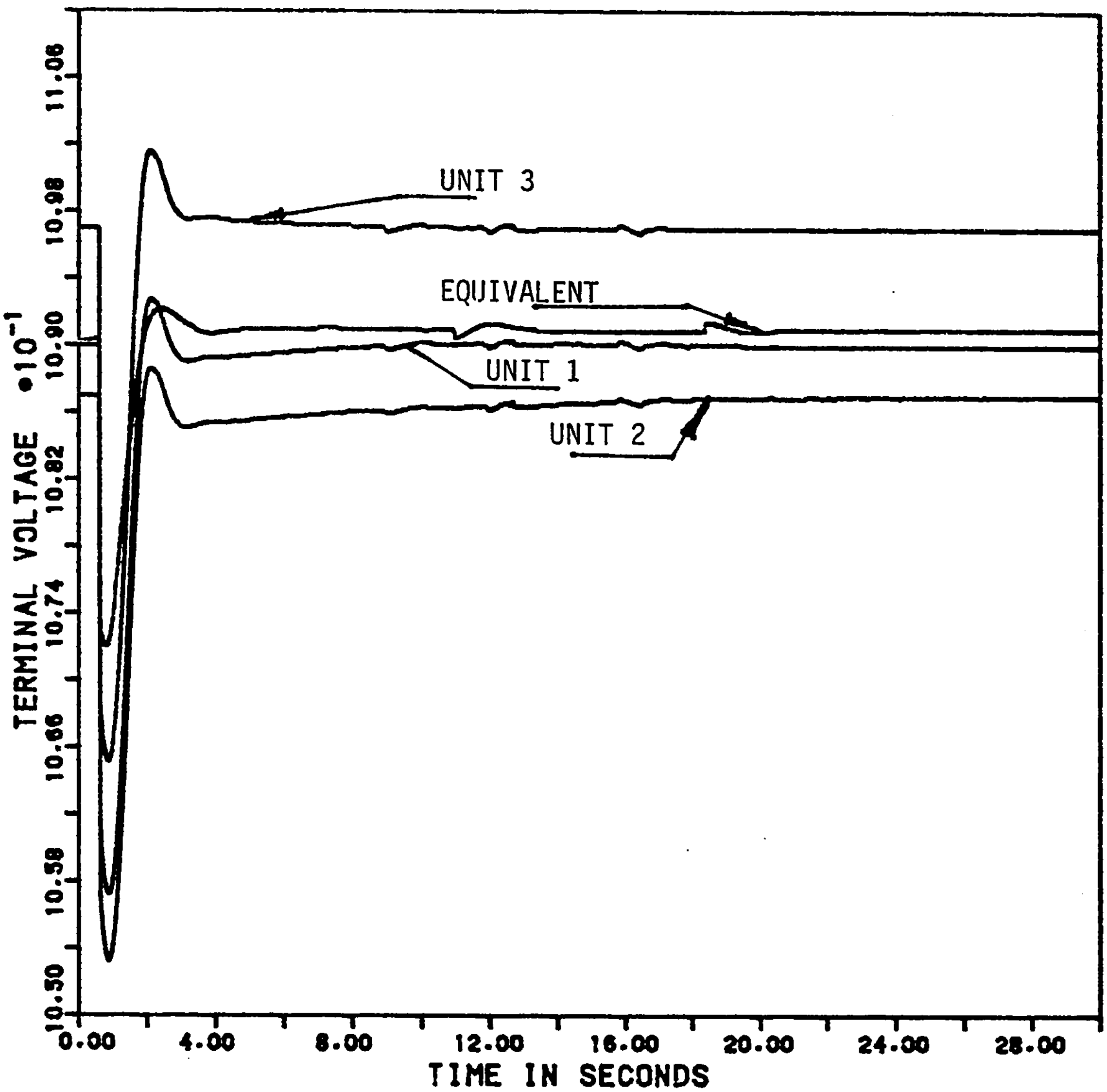


Figure 4.6 3 Machine System Case 2 : Terminal Voltage of Individual and Equivalent Power Plant Units.

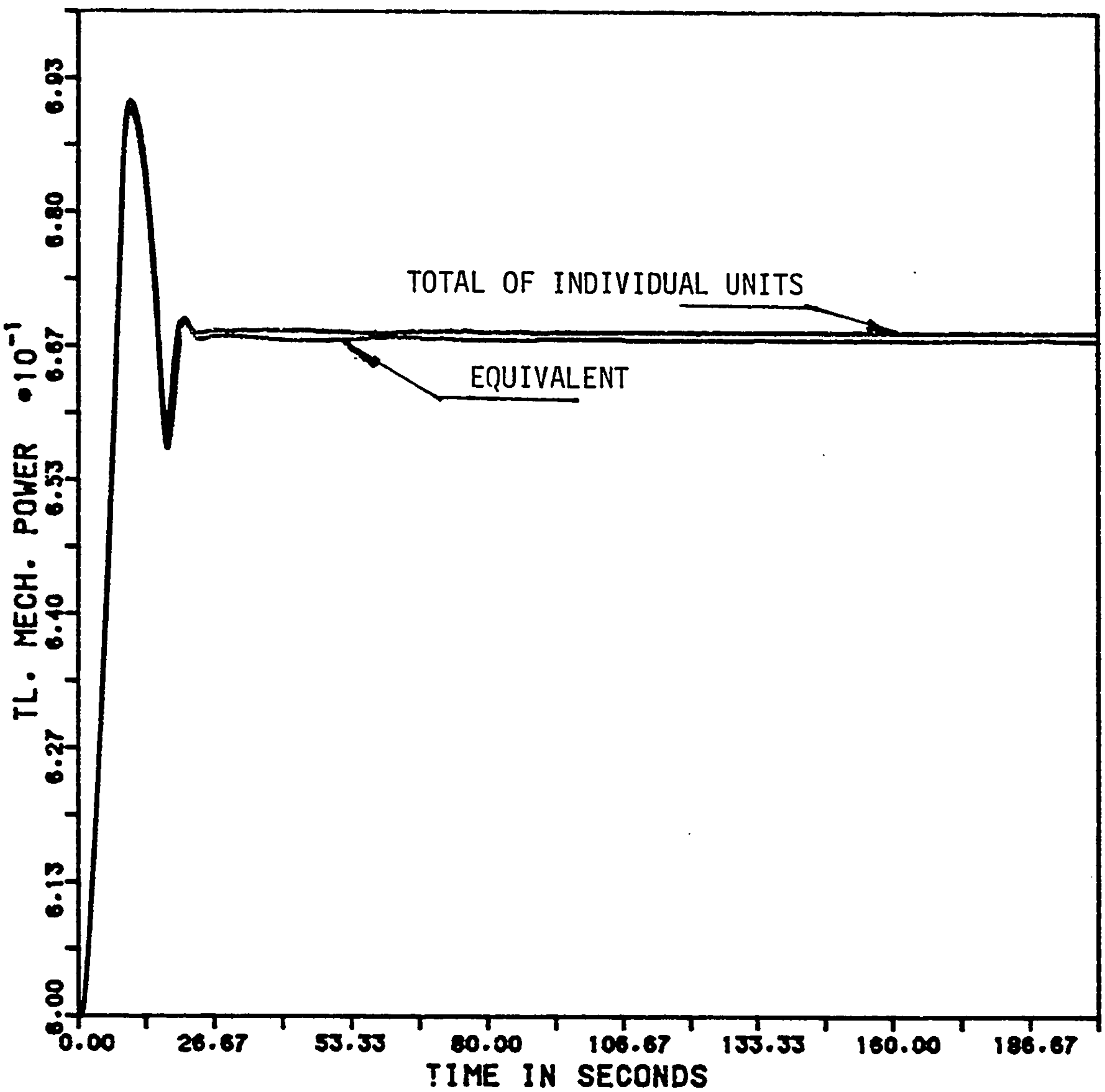


Figure 4.7 3 Machine System Case 2 : Total Mechanical Power Output of the Individual Power Plant Units and Mechanical Power Output of the Equivalent.

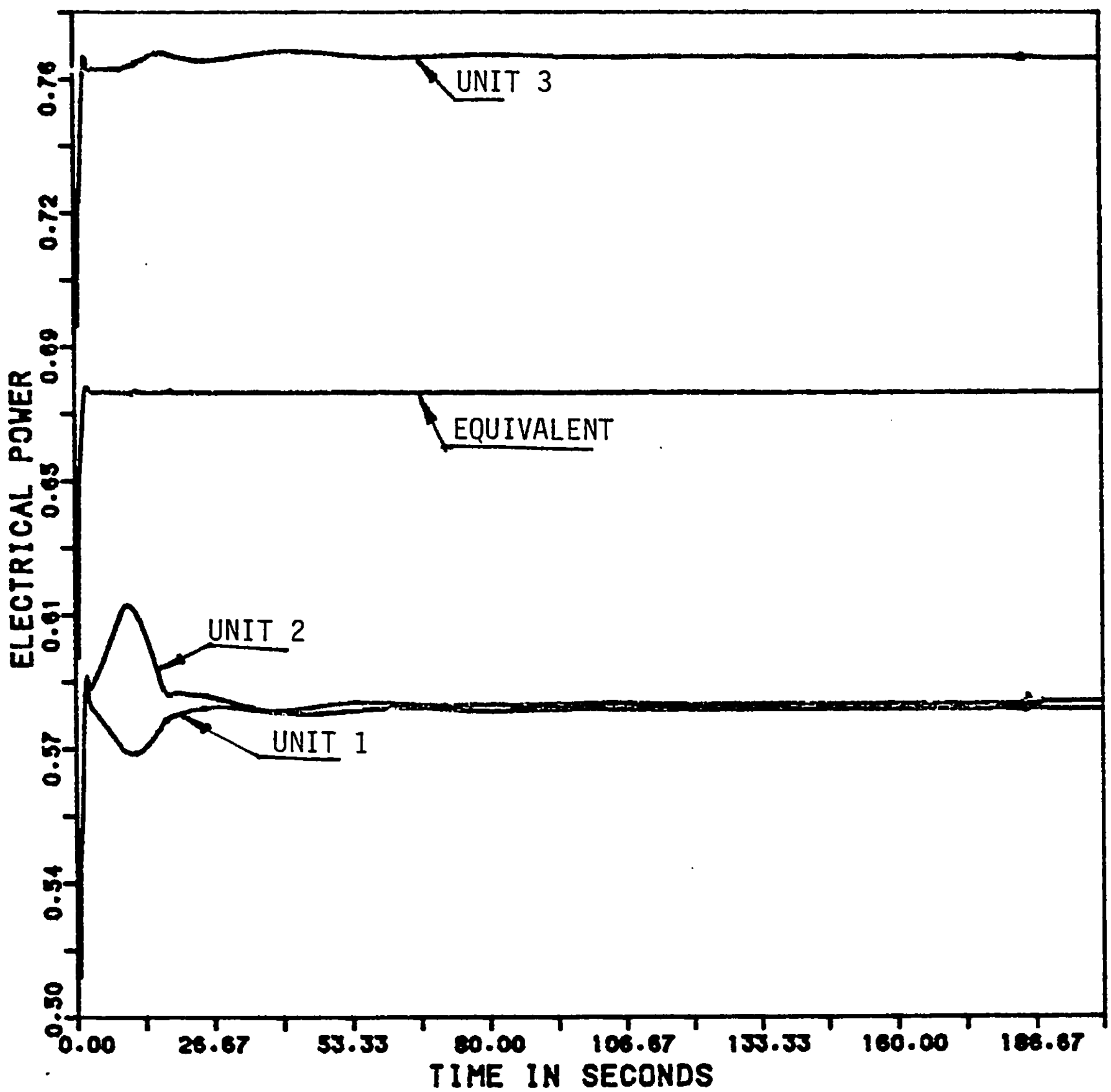


Figure 4.8 3 Machine System Case 2 : Electrical Power Output of Individual and Equivalent Power Plant Units.

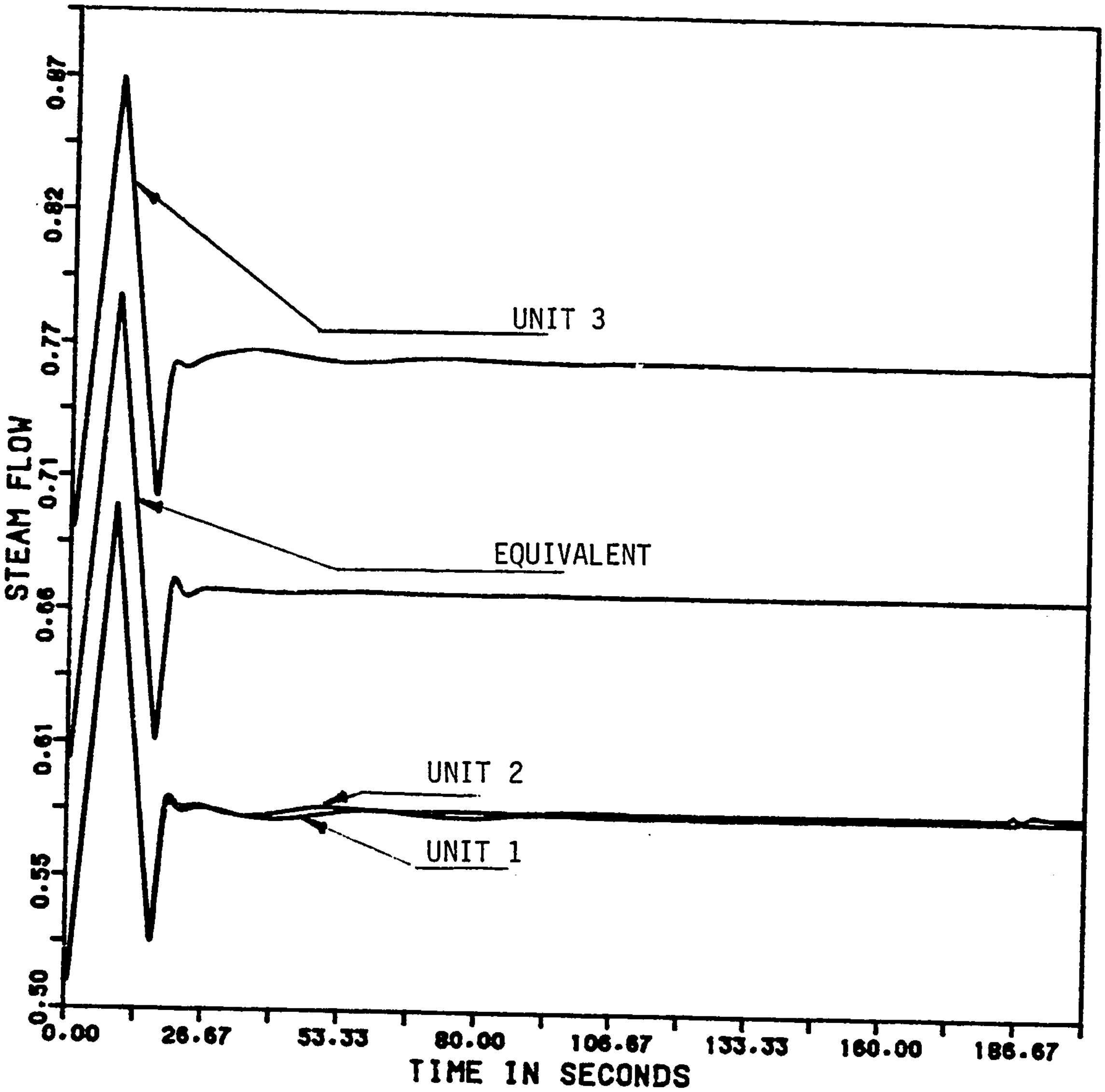


Figure 4.9 3 Machine System Case 2 : Steam Flow of Individual and Equivalent Power Plant Units.

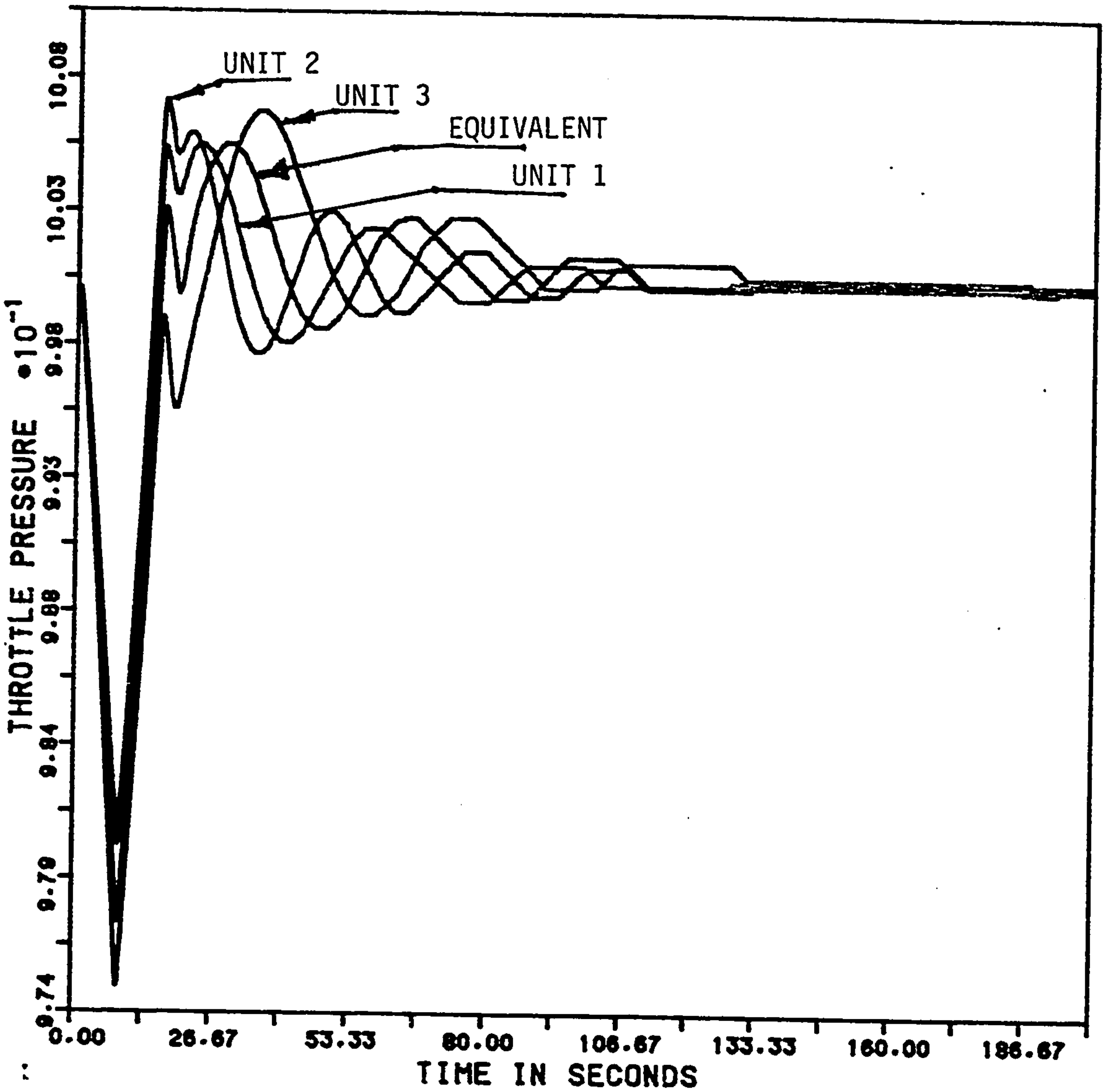


Figure 4.10 3 Machine System Case 2 : Throttle Pressure of Individual and Equivalent Power Plant Units.

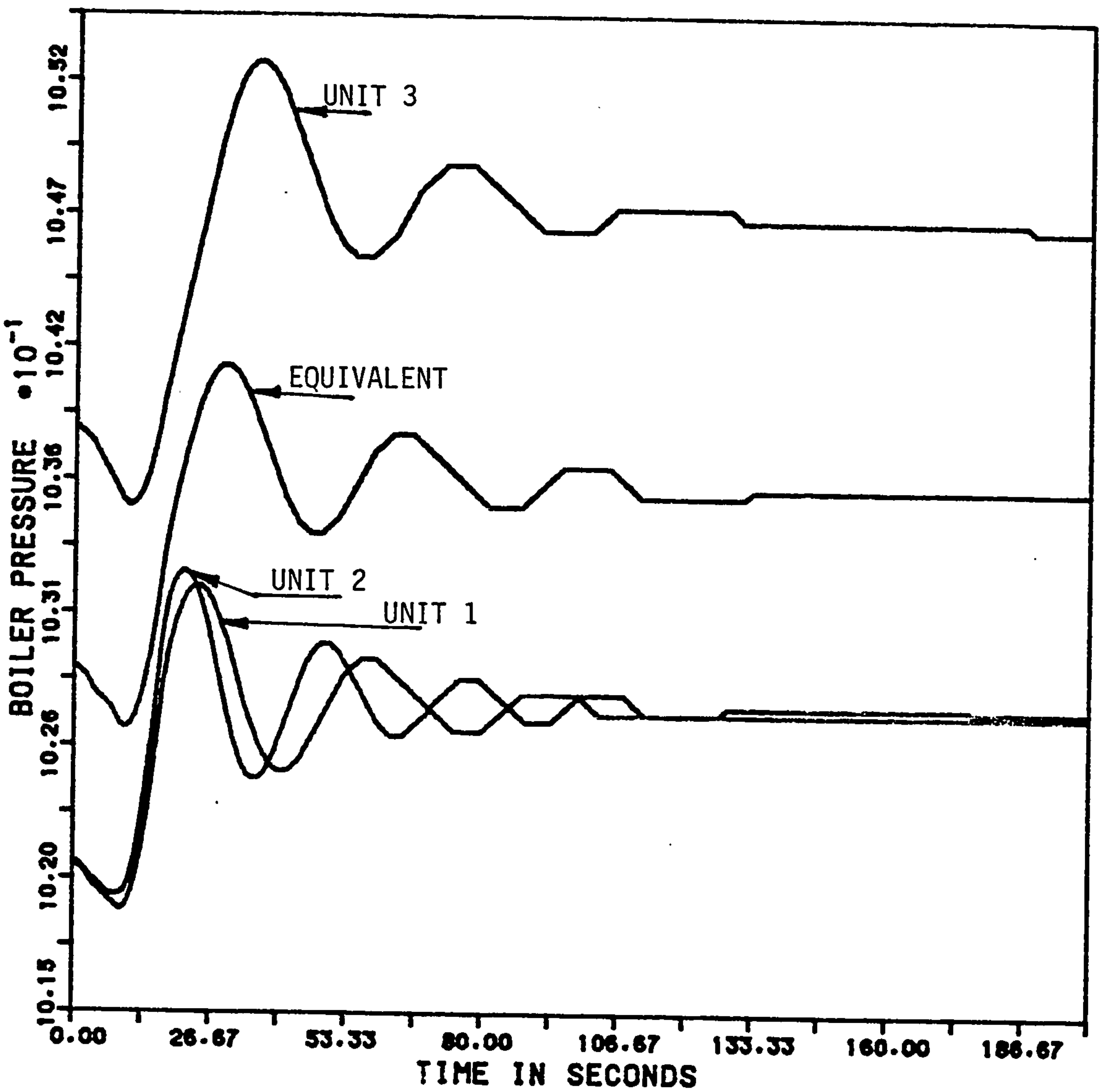


Figure 4.11 3 Machine System Case 2: Boiler Pressure of Individual and Equivalent Power Plant Units.

The network diagram of the test system is shown in Fig. 4.12. For test purpose, the system is divided into study system and an external system. Study and external systems are interconnected through the lines at three designated buses in the study system.

Two types of contingencies are considered in order to compare the time responses of the equivalent with that of a full system.

The contingencies considered are:

i) Loss of Load

ii) Three Phase Fault With Loss of Load.

4.5.1 Case 1: Loss of Load

At time t=0, the system is assumed to be at steady state, at t=0.2 seconds, load at bus 26, 28 and 29 are lost. The lost load is about 10% of the total system load.

The contingency was simulated for the full system, using the long term dynamic simulation program and it was found by comparison of swing curve that the power plant unit 2 and 3 forms a coherent group and power plant unit 4, 6 and 7 forms another coherent group. Two equivalent power plant units were formed for the two coherent groups respectively, using the aggregation

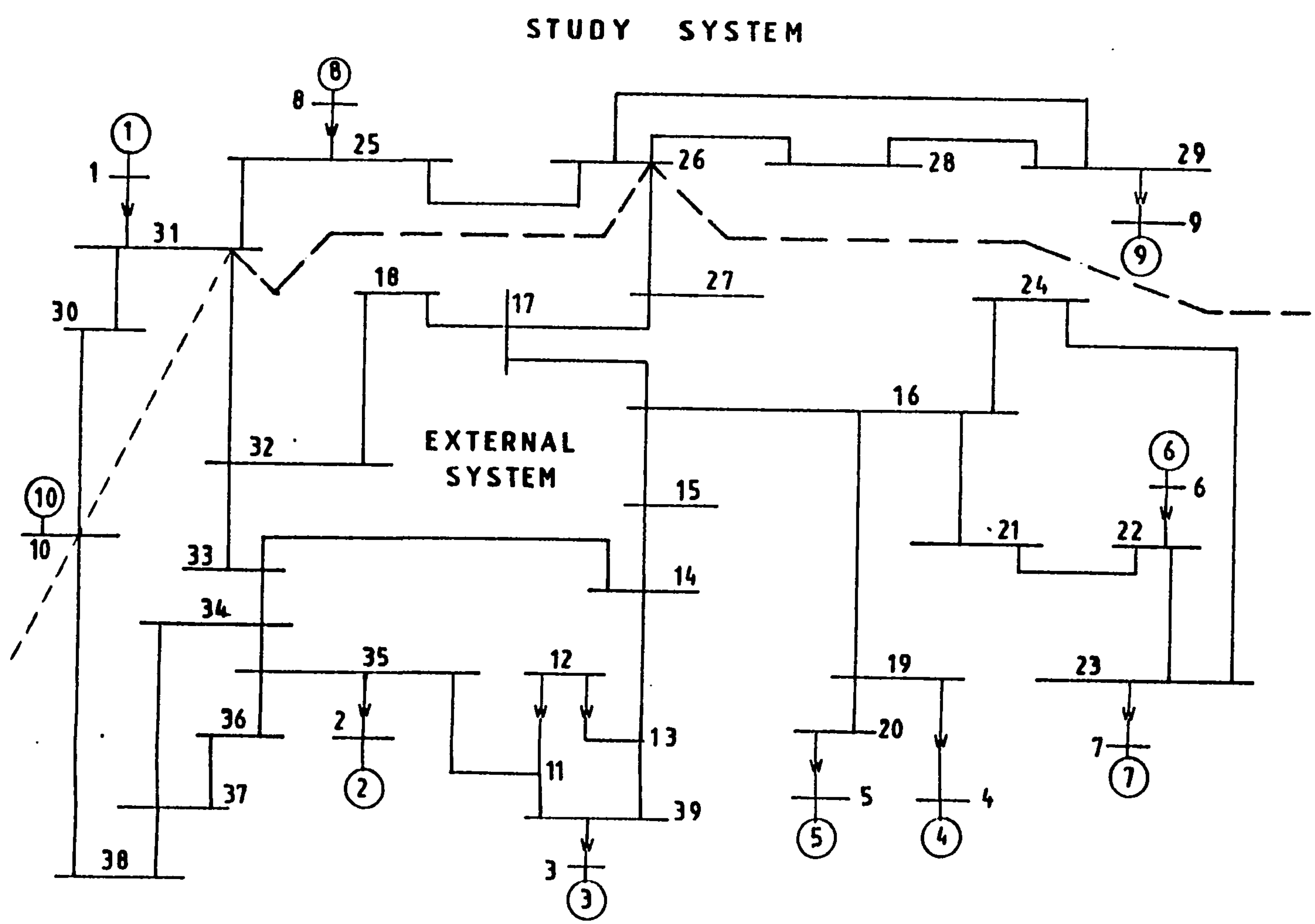


Figure 4.12 39 Bus, New England System

procedure explained in Chapter II. Finally the load and the coherent units buses are reduced to form an equivalent system.

Again the same contingency was simulated for the equivalent system. The responses for full system and equivalent simulations are compared. Samples of the result are shown in Figs. 4.13 through 4.21 and are explained below:

- Figure 4.13 - The rotor angle of the two coherent units i.e. units 2 and 3 are compared with the rotor angle of their equivalent.
- Figure 4.14 - The frequency of the unit 2 is compared with the frequency of its group equivalent.
- Figure 4.15 - The total mechanical power output of the three coherent unit (units 4, 6 and 7) is compared with the mechanical power output of their equivalent.
- Figure 4.16 - The mechanical power for the units 4, 6 and 7 and their equivalent are plotted.
- Figure 4.17 - The steam flow for the units 2 and 3 and their equivalent are plotted.

Figures 4.18 and 4.19 - The throttle pressure and boiler pressure for the units 2 and 3 and for their equivalent are compared.

Figures 4.20 and 4.20 - The throttle pressure and boiler pressure for the units 4, 6 and 7 and for their equivalent are compared.

There is a good agreement between the total mechanical power outputs obtained by the individual power plant units and the mechanical power output of their equivalent. The frequency of the equivalent matches with that of the individual unit.

4.5.2 Case 2: Three Phase Fault With Loss of Load

At time t=0, the system is assumed to be at steady state, at t=0.2 seconds there is a three phase fault at bus 29, the fault is cleared after 3 cycles i.e. at t=0.25 seconds by opening the line 26-29, at t=30 seconds the line is restored back, but at t=50 seconds the load at bus 26 and 29 are lost, which amounts to about 7% of the total load and is restored back at t=150 seconds.

The dynamics resulting from the above disturbance was simulated for the full system, as in Case 1 the coherent groups of power plant unit were identified, which were found to be the same as in Case 1, which implies that the equivalent is also the same as that in Case 1.

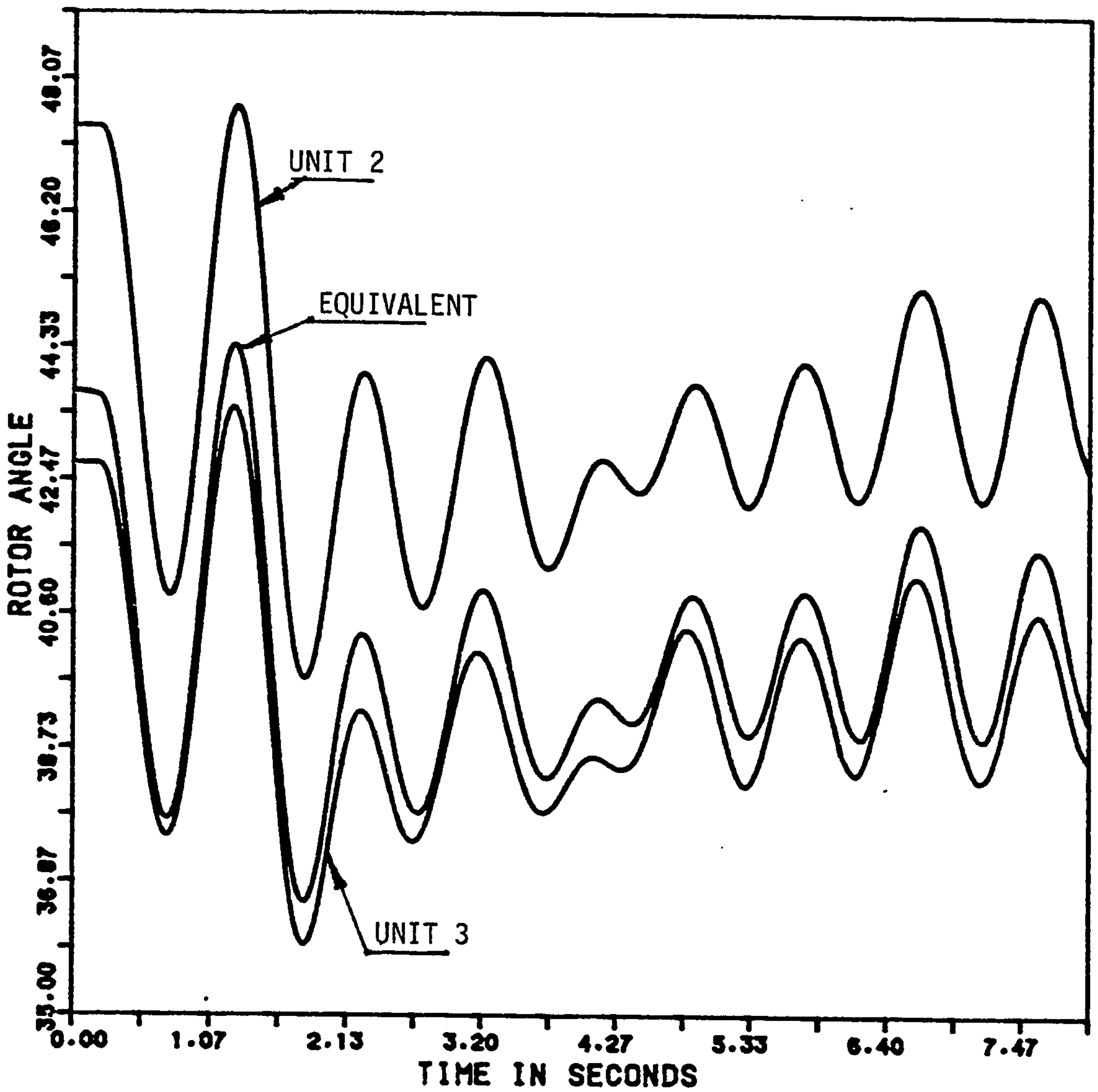


Figure 4.13 39 Bus System Case 1 : Rotor Angle of the Individual and Equivalent Power Plant Units.

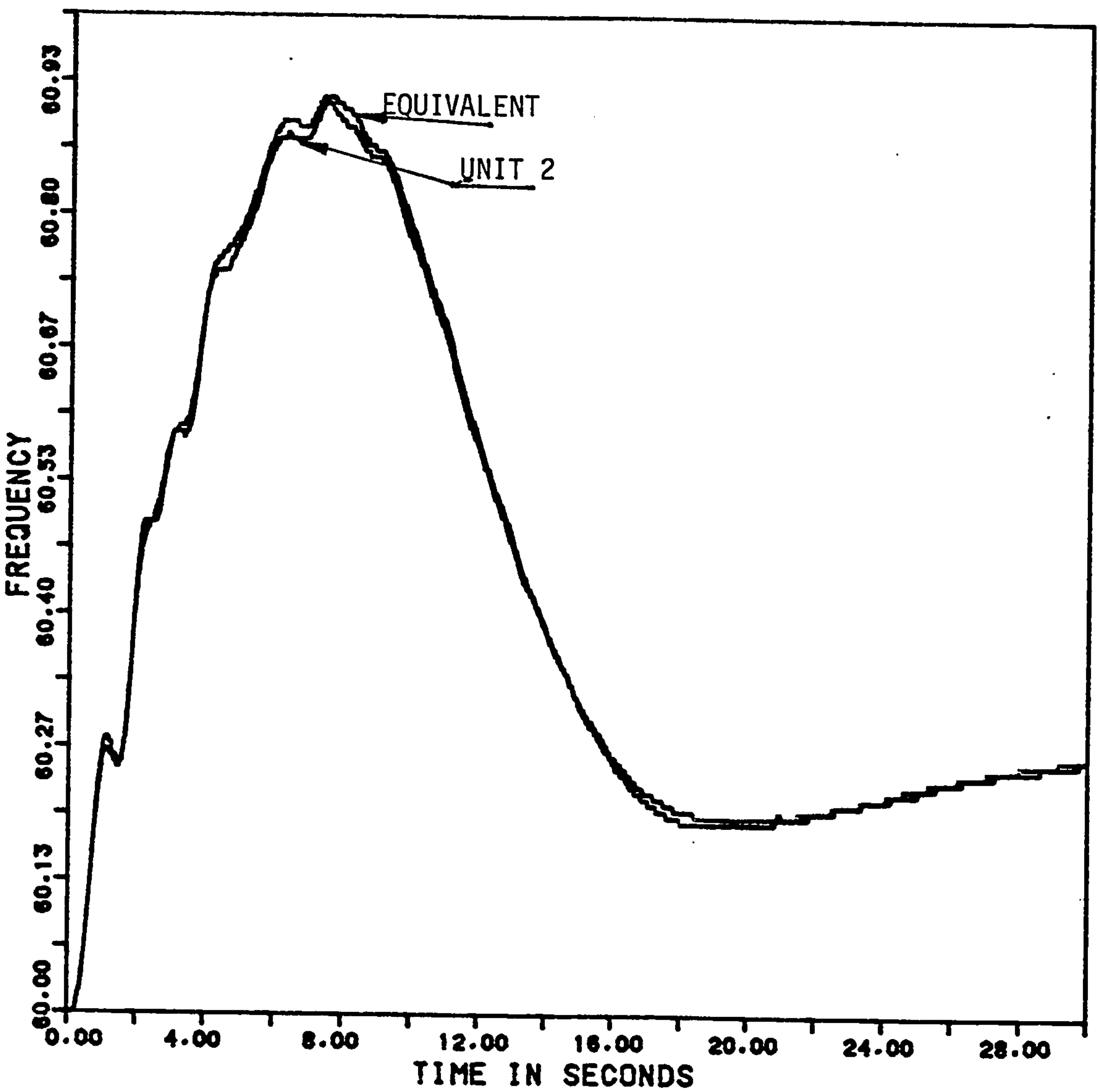


Figure 4.14 39 Bus System Case 1 : Frequency of the Individual and Equivalent Power Plant Units.

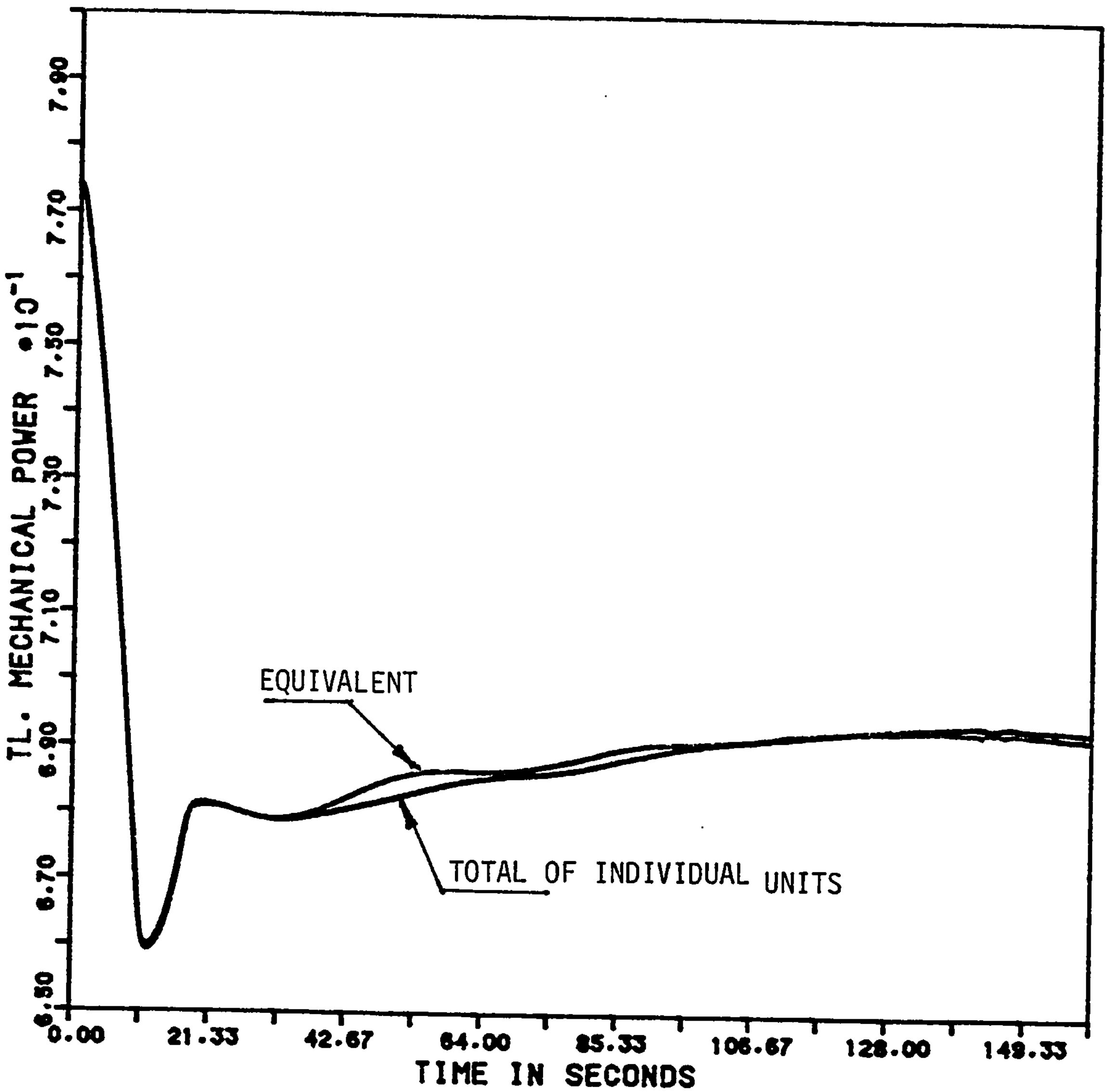


Figure 4.15 39 Bus System Case 1 : Total Mechanical Power Output of Individual Power Plant Units and Mechanical Power Output of Equivalent.

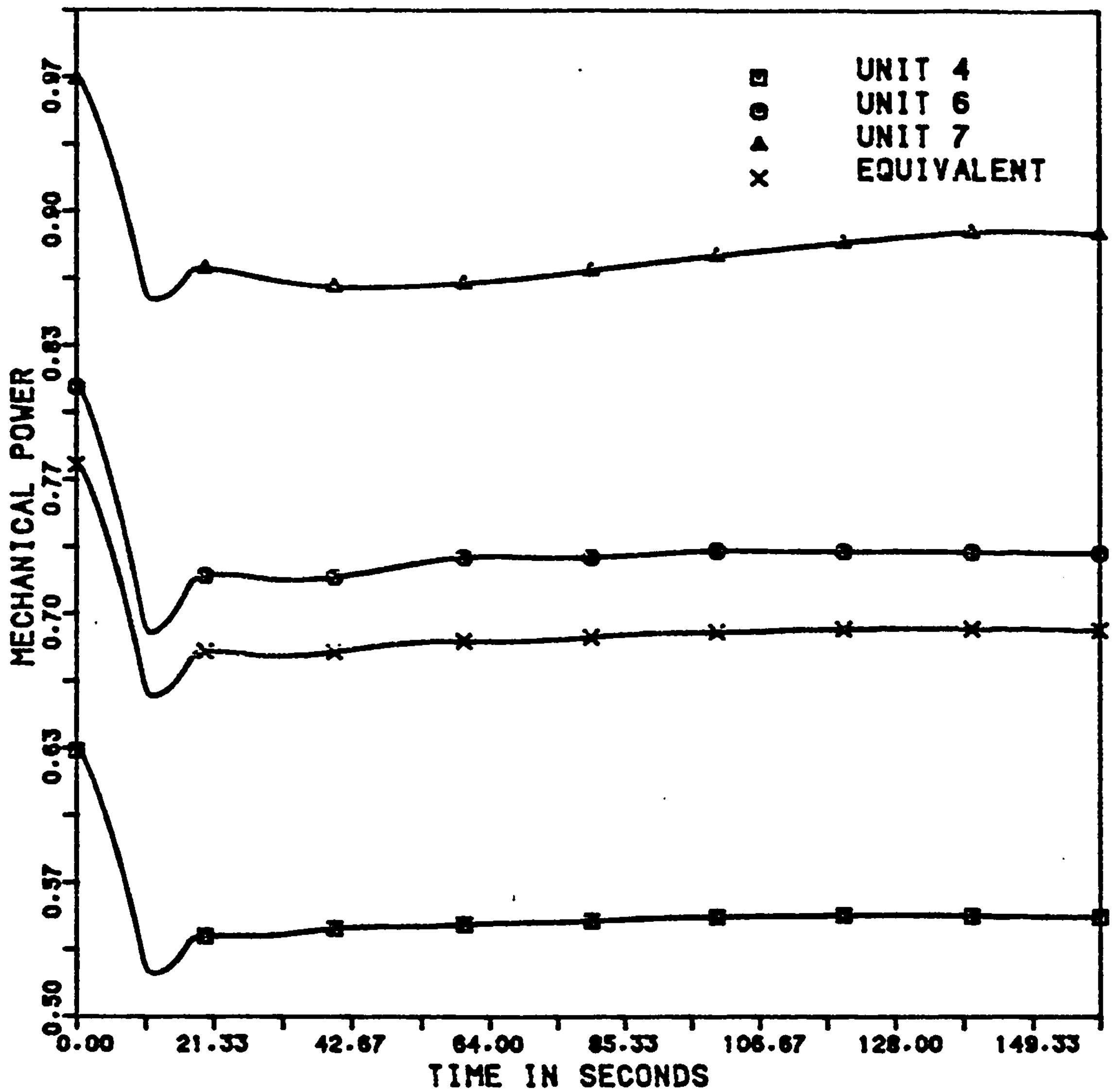


Figure 4.16 39 Bus System Case 1: Mechanical Power Output of Individual and Equivalent Power Plant Units.

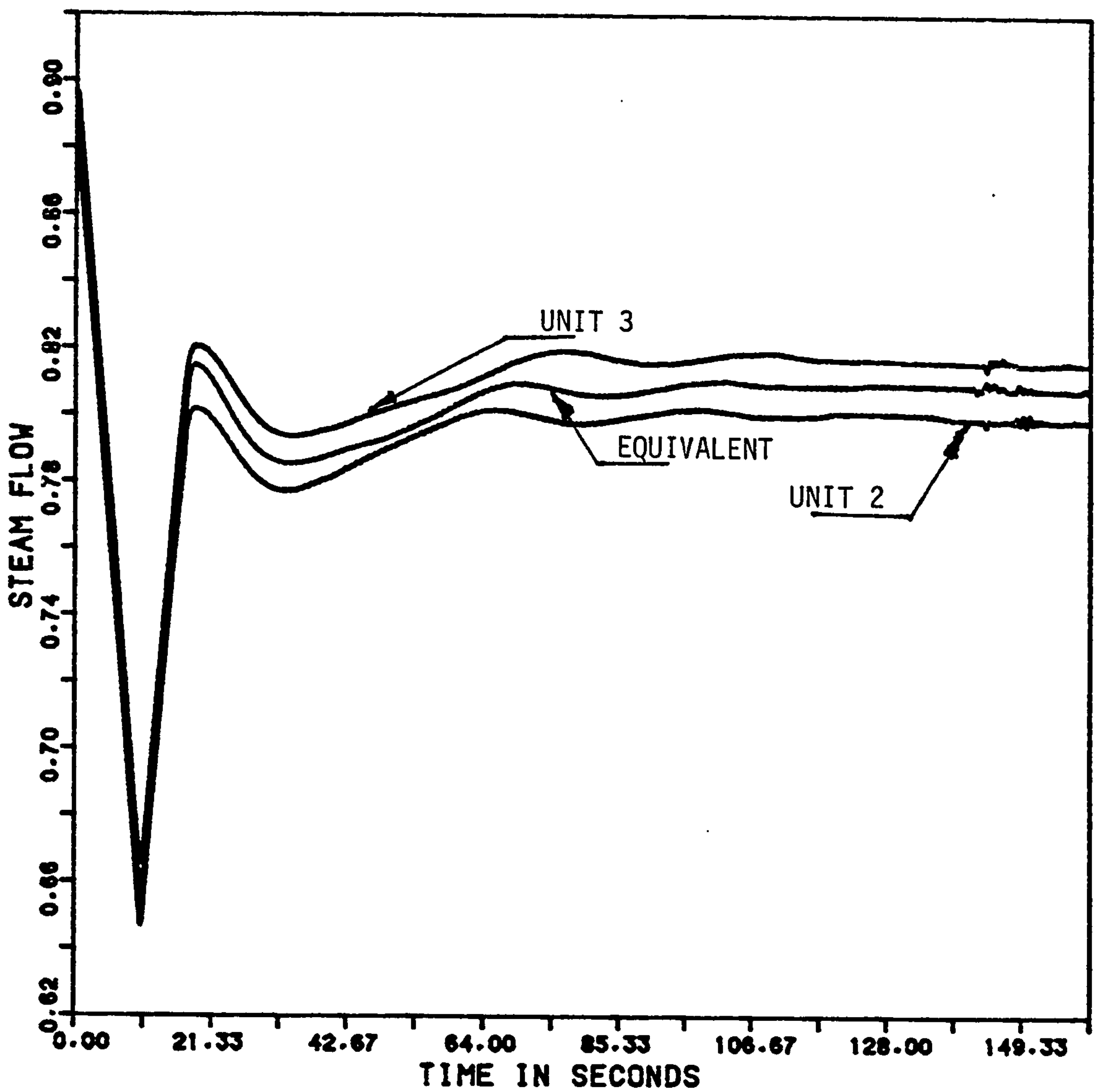


Figure 4.17 39 Bus System Case 1: Steam Flow of Inidvidual and Equivalent Power Plant Units.

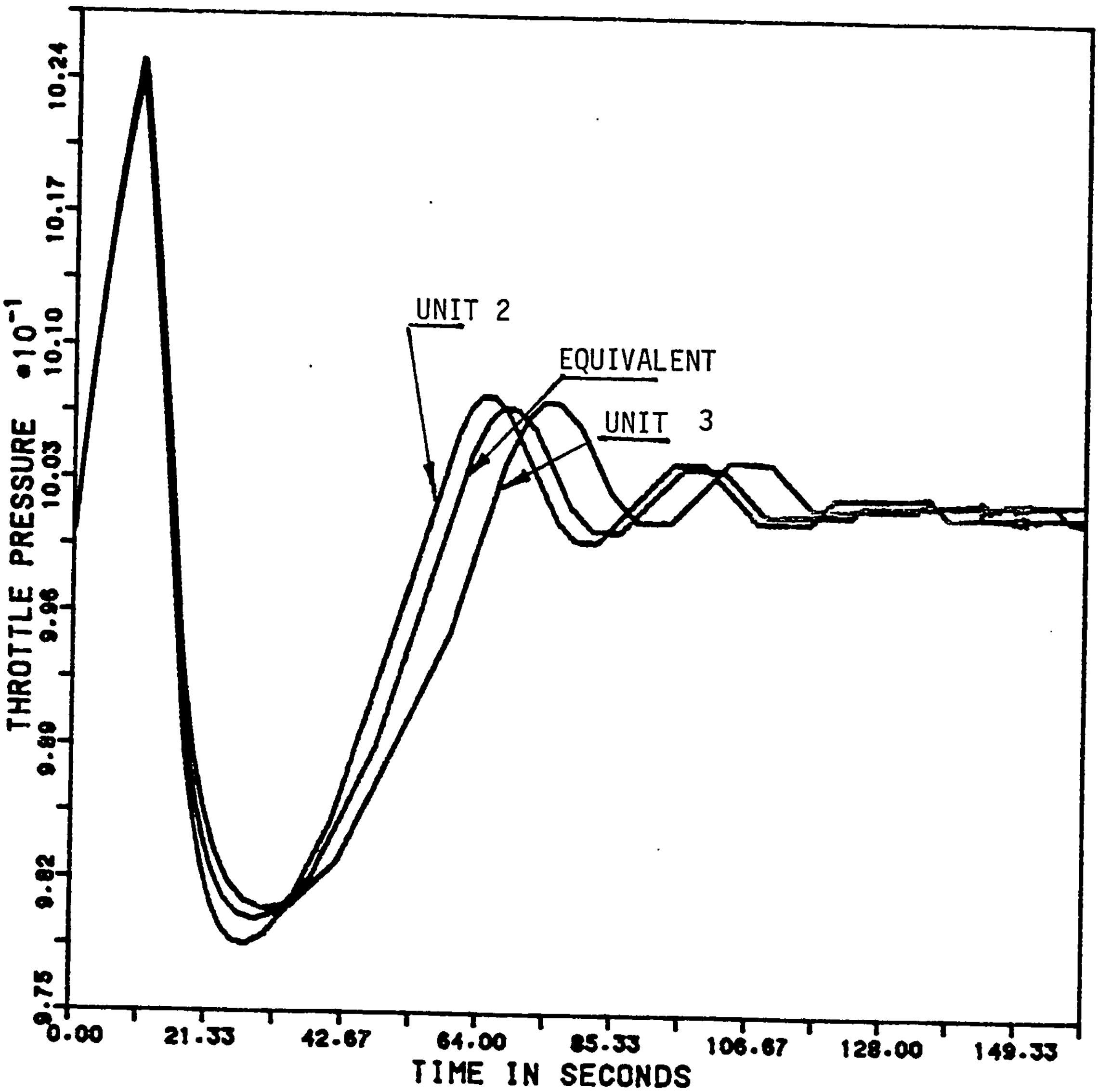


Figure 4.18 39 Bus System Case 1: Throttle Pressure of Individual and Equivalent Power Plant Units.

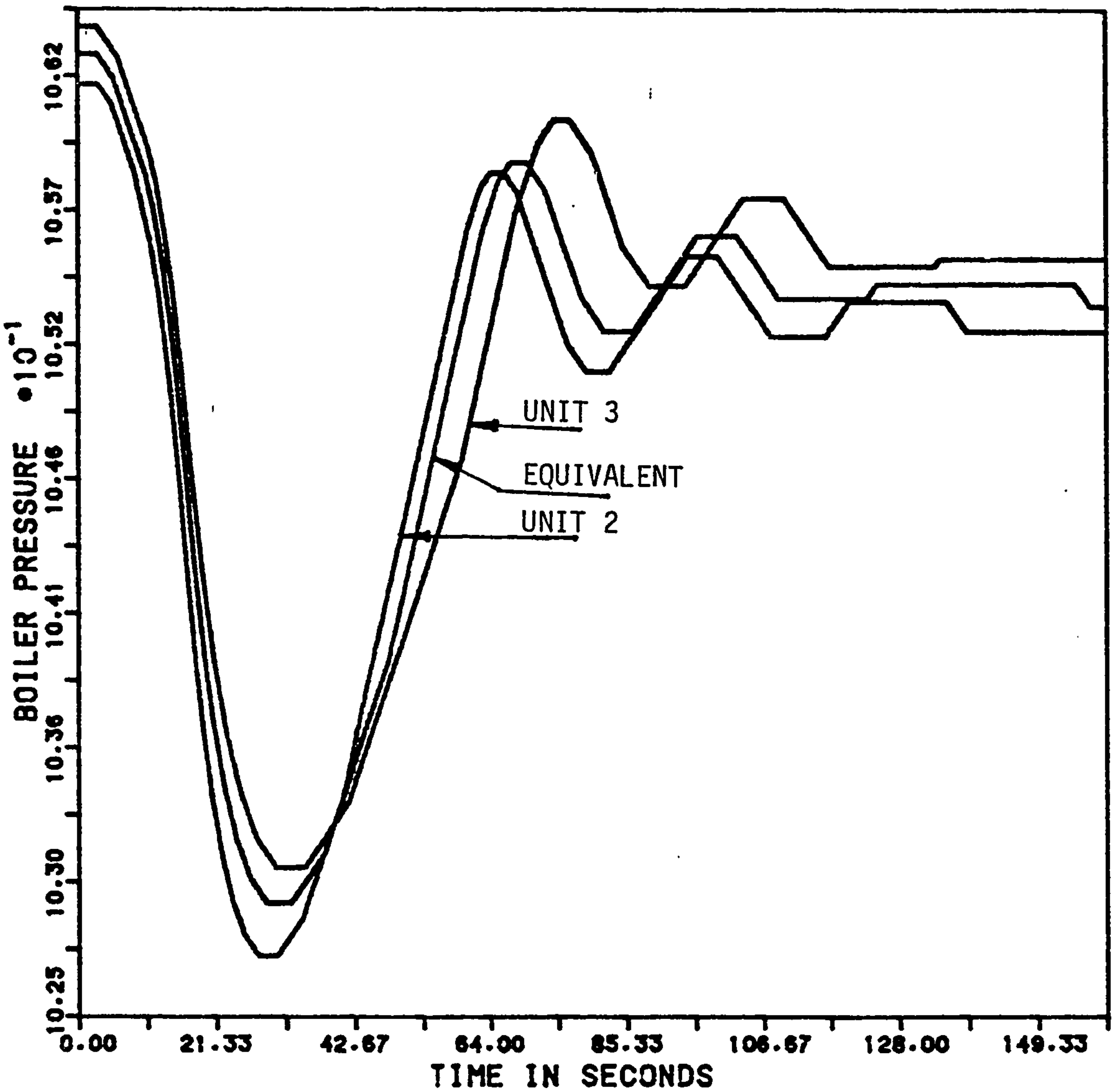


Figure 4.19 39 Bus System Case 1: Boiler Pressure of Individual and Equivalent Power Plant Units.

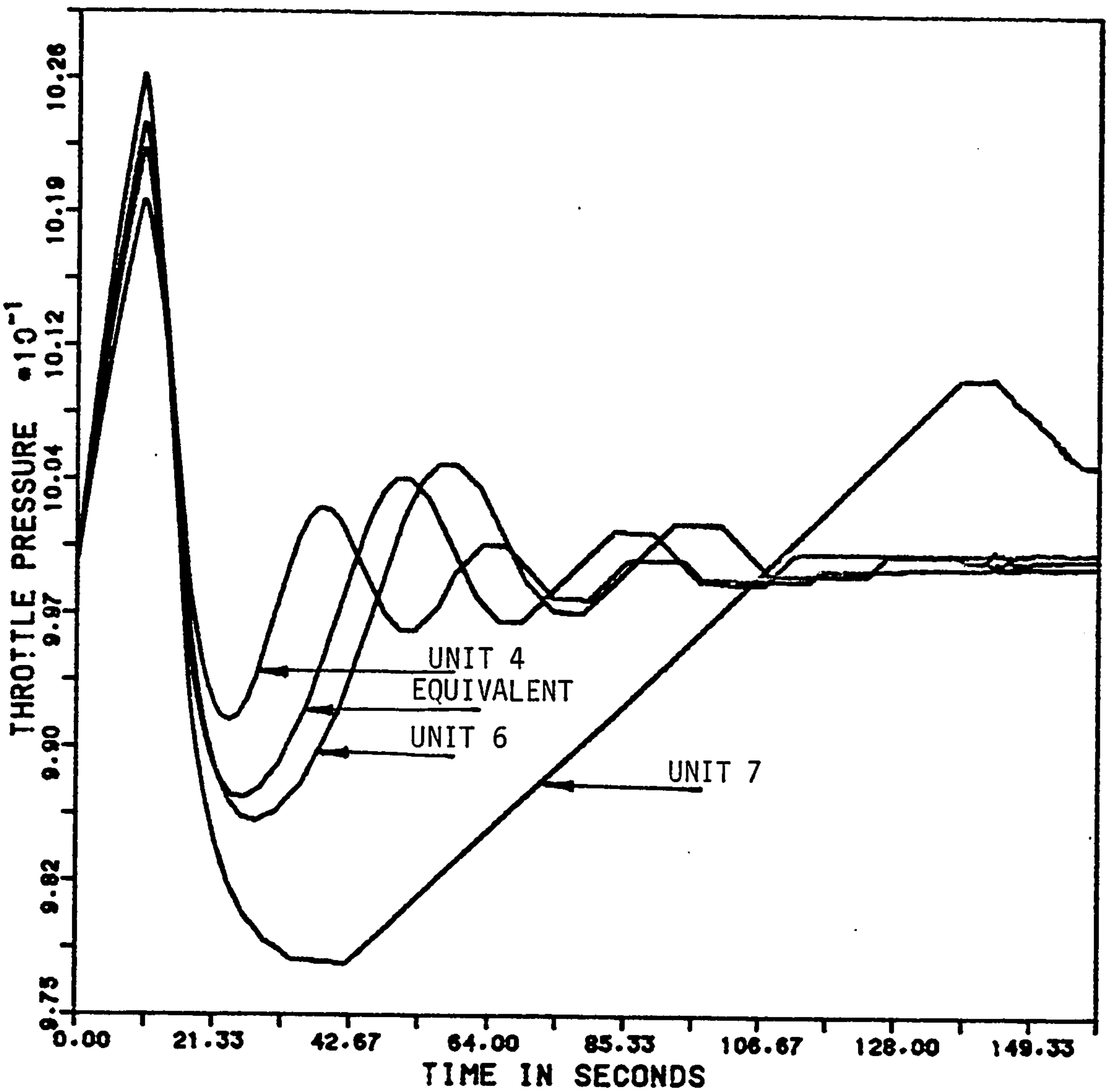


Figure 4.20 39 Bus Case 1: Throttle Pressure of Individual and Equivalent Power Plant Units.

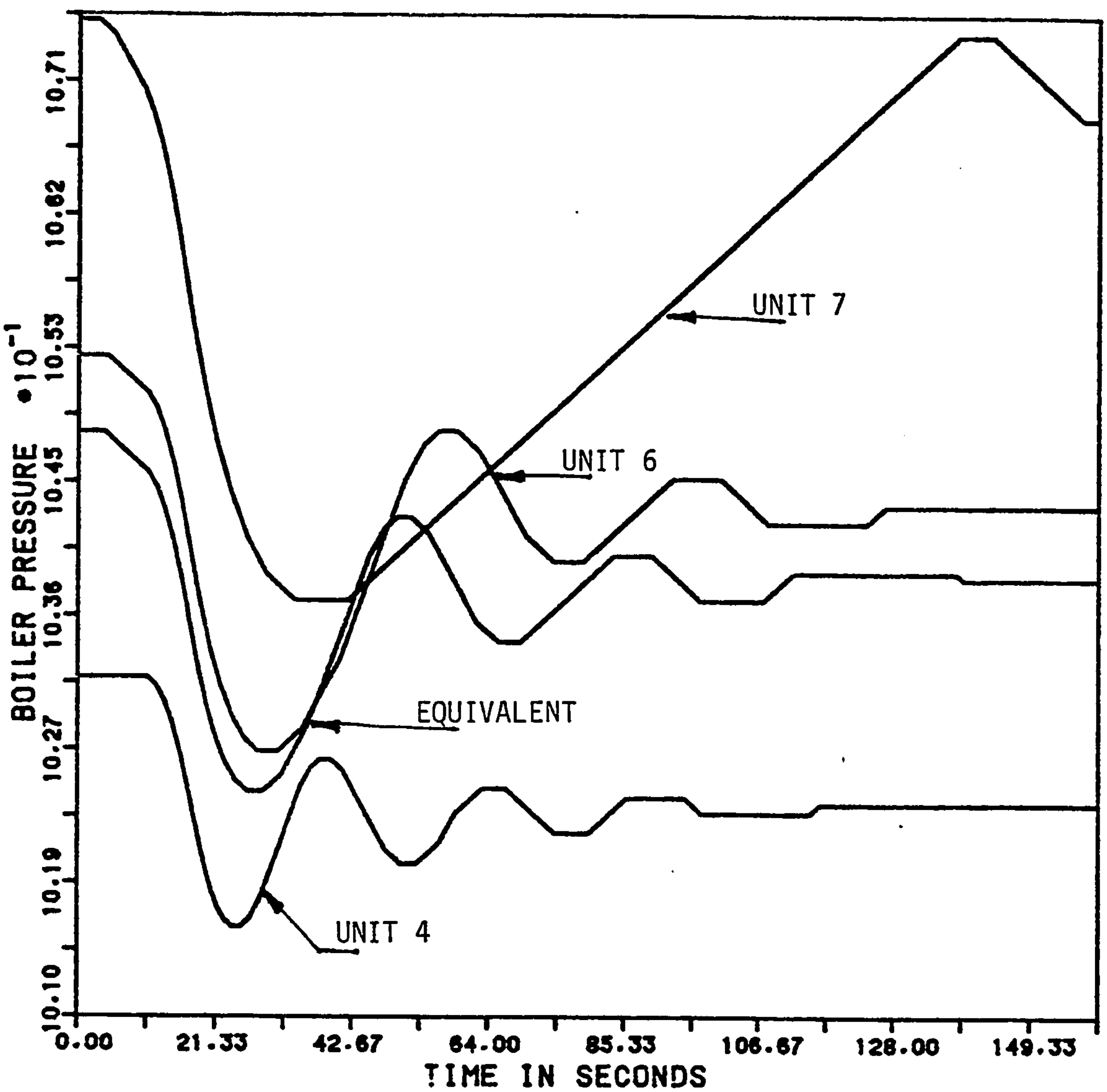


Figure 4. 21 39 Bus System Case 1 : Boiler Pressure of Individual and Equivalent Power Plant Units.

Again the same disturbance was simulated for the equivalent. The simulation period was 300 seconds for both the full system and the equivalent. The responses for full system and equivalent simulations are compared. Samples of the results are shown in Figs. 4.22 through 4.28 and are described below:

- Figures 4.22 and 4.23 - The rotor angle of the individual units and their equivalent are compared, for both the coherent groups.

- Figure 4.24 - The total mechanical power output of the two coherent unit (units 2 and 3) is compared with the mechanical power output of its equivalent.

- Figure 4.25 - The mechanical power for the units 2 and 3 and their equivalent are plotted.

- Figure 4.26 - The steam flow for the units 4, 6 and 7 and their equivalent are plotted.

- Figures 4.27 and 4.28 - The throttle pressure and boiler pressure for the units 2 and 3 and their equivalent are compared.

The conclusions are the same as in Case. 1.

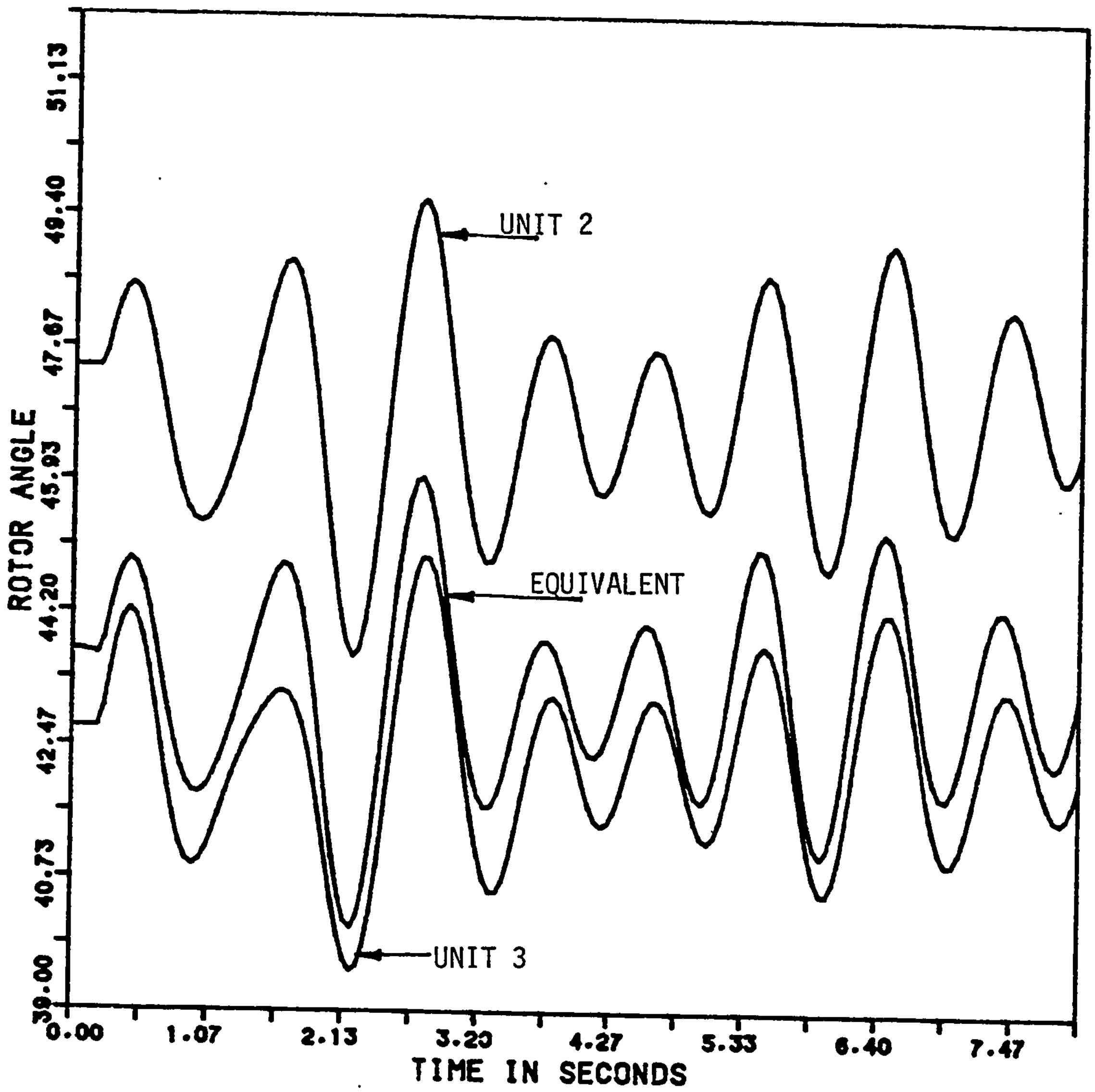


Figure 4.22 39 Bus System Case 2: Rotor Angle of Individual and Equivalent Power Plant Units.

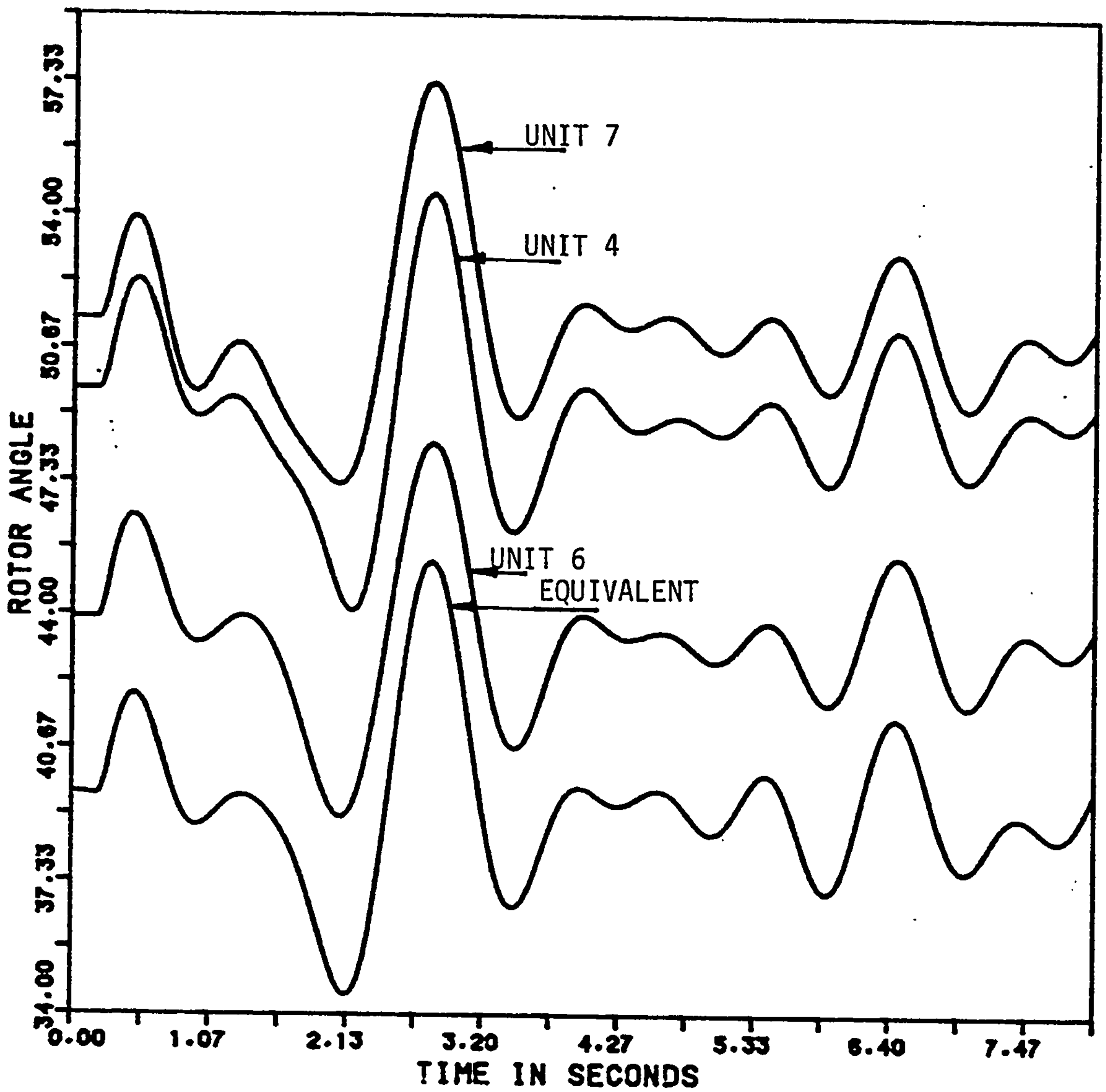


Figure 4.23 39 Bus System Case 2 : Rotor Angle of Individual and Equivalent Power Plant Units.

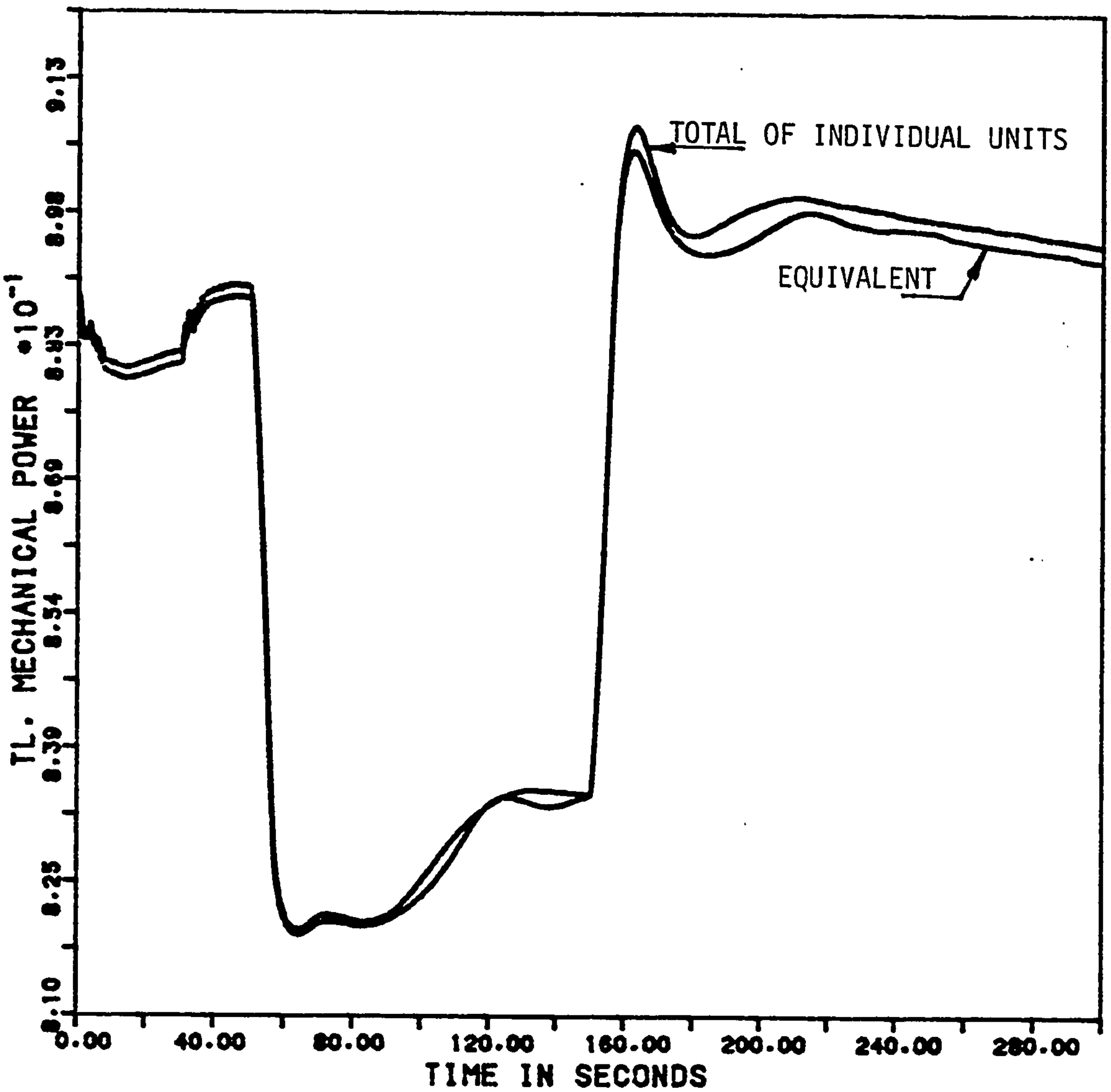


Figure 4.24 39 Bus System Case 2 : Total Mechanical Power Output of the Individual Power Plant Units and Mechanical Power Output of Equivalent.

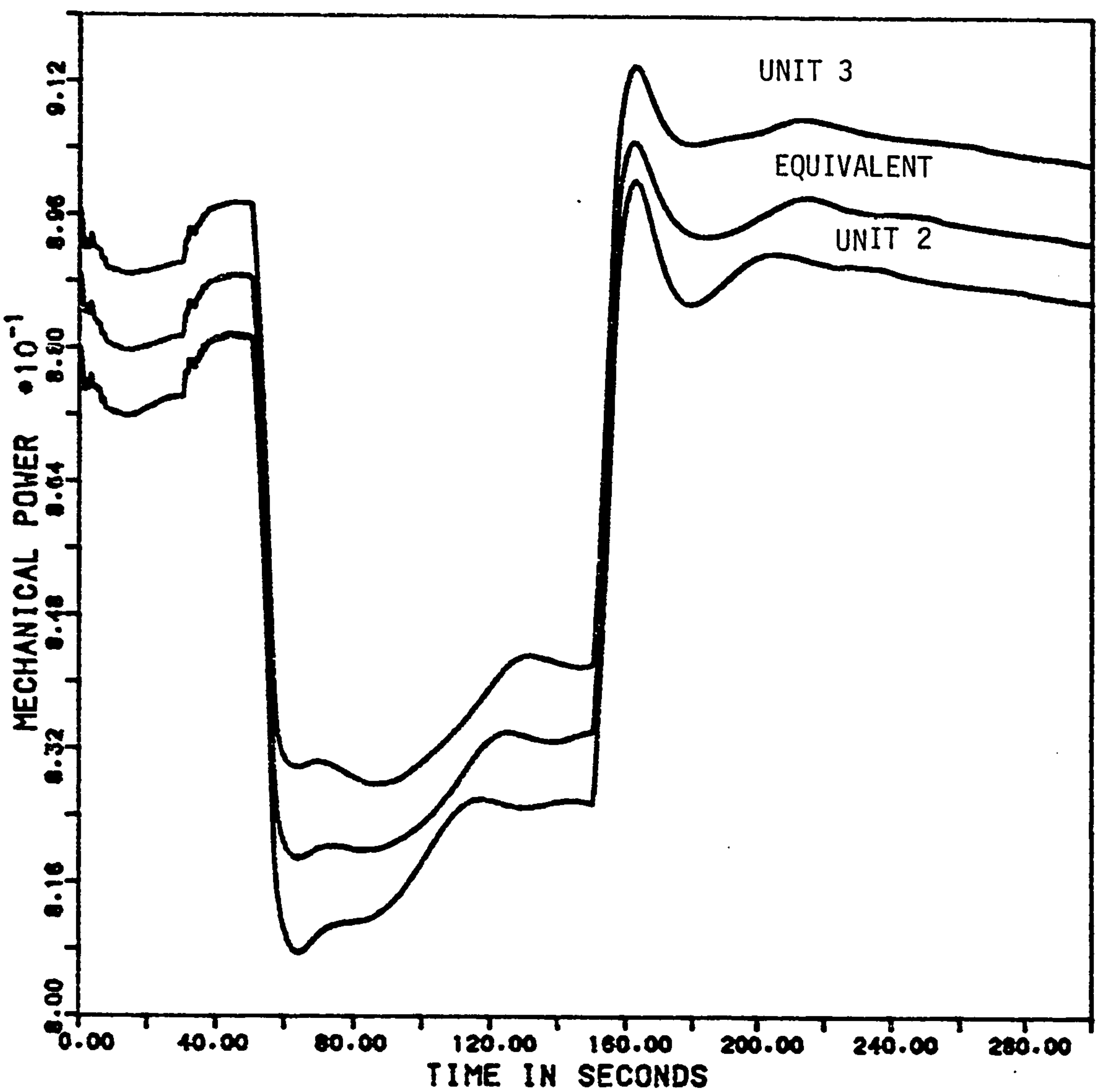


Figure 4.25 39 Bus System Case 2 : Mechanical Power Output of Individual and Equivalent Power Plant Units.

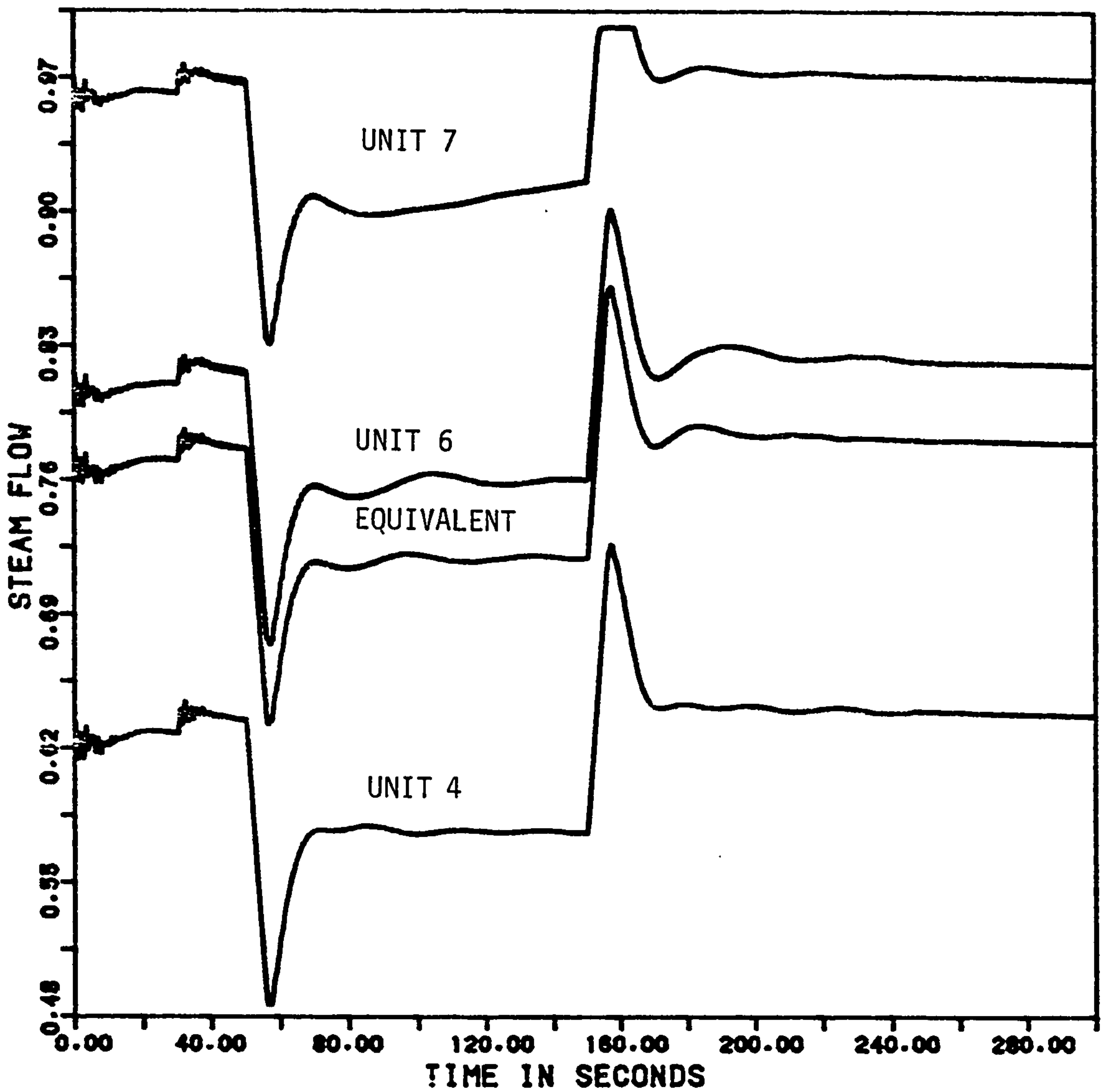


Figure 4.26 39 Bus System Case 2 : Steam Flow of Individual and Equivalent Power Plant Units.

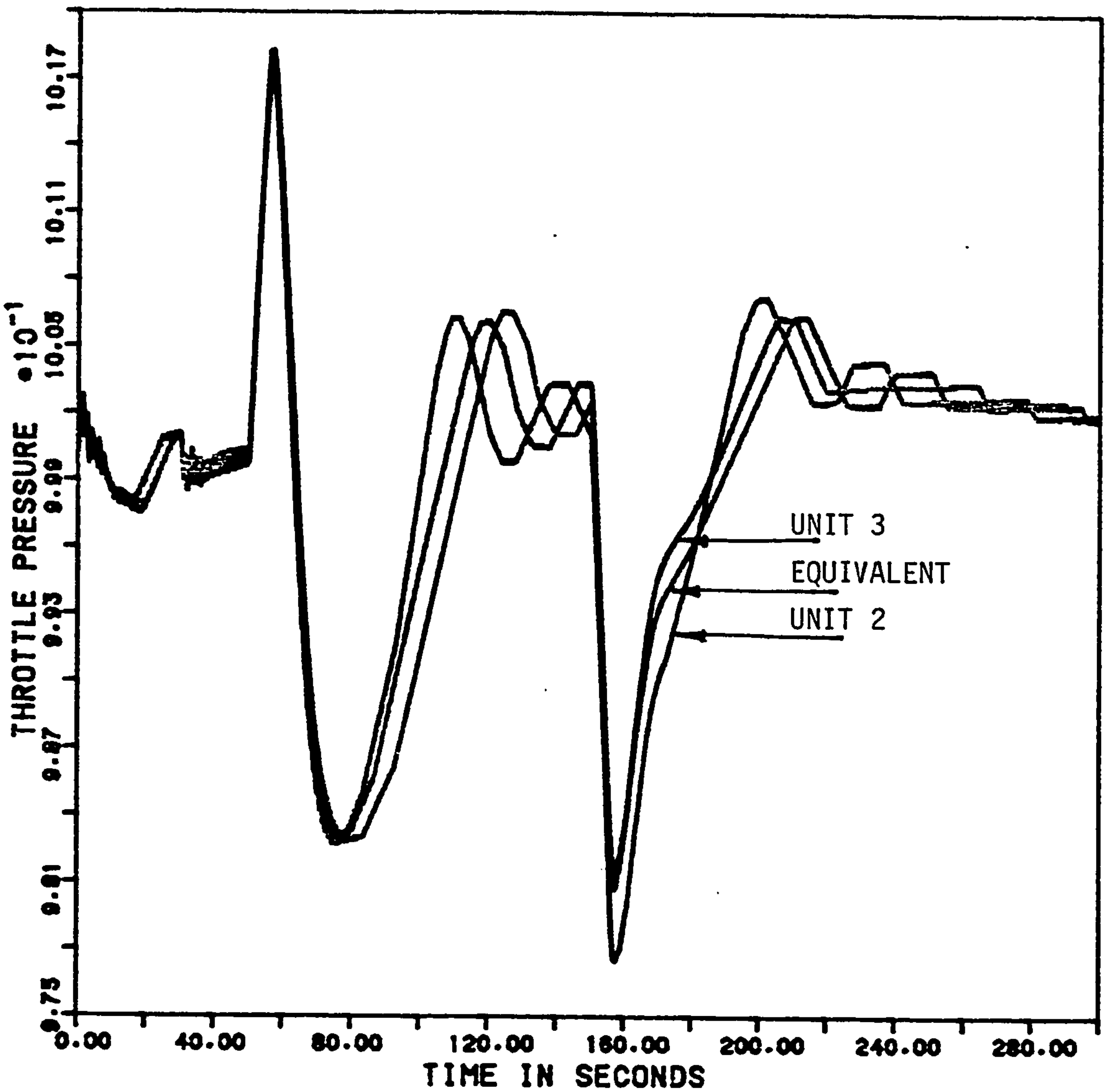


Figure 4.27 39 Bus System Case 2 : Throttle Pressure of Individual and Equivalent Power Plant Units.

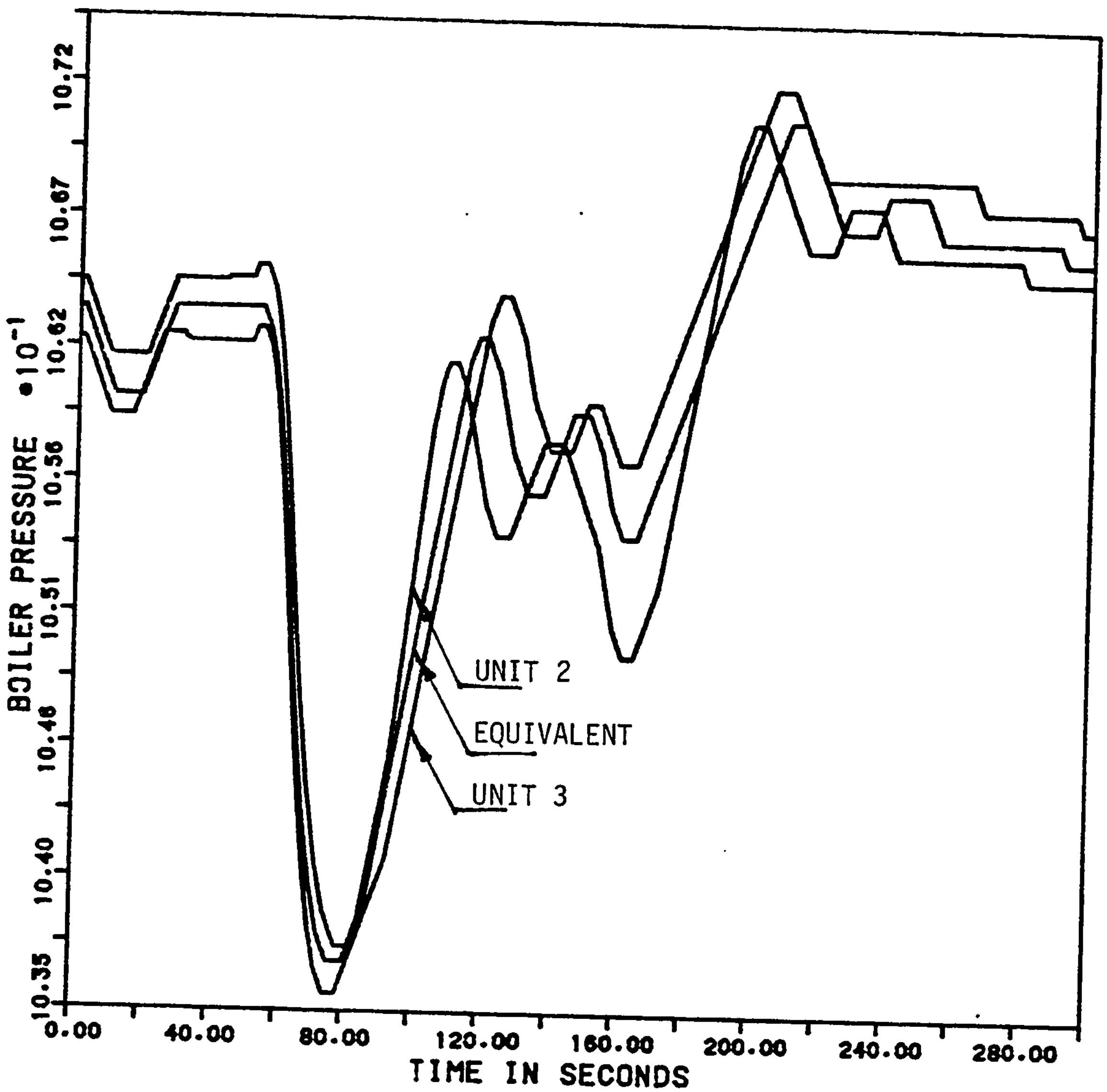


Figure 4.28 39 Bus System Case 2: Boiler Pressure of Individual and Equivalent Power Plant Units.

Chapter V

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

The major study findings and accomplishment of this thesis are:

1. The coherency based model reduction technique for aggregation of power plant model has been developed which includes a detailed turbine model, boiler controls, boiler dynamics and power plant auxiliaries.

2. The effect of operating point, model decomposition and variation in power plant parameters on the equivalent parameter value are negligible.

3. The dynamic equivalent has produced simulation responses which agree very much closely with the responses obtained by simulating the full system.

4. Coherency-Based Dynamic Equivalent can be represented by the same models which are presently used for modelling the normal power plants components, therefore, they can be used

without changes to the existing Long-Term Dynamic Stability Programs.

5. A conventional Transient Stability program has been modified, to include a detailed model of turbine, turbine controls, boiler, boiler controls, and power plant auxiliaries.

5.2 RECOMMENDATIONS

Future work may include the following:

1. Investigation of applicability of other aggregation method reported in control system literature such as Error Minimization Methods, Routh Approximation, Continued Fraction Method, etc.

2. Development of a generalized model which represents group of coherent power plant units, consisting of nuclear, hydro and steam power plants for long-term dynamic studies.

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APPENDIX A

A-1. OPERATIONAL ADMITTANCES OF THE SYNCHRONOUS MACHINE

Referring to Figure A-1 and to the usual definition of the per unit reactances and time-constants, the differential equations of a synchronous machine with transient saliency reads:

$$e'_q = (Ke_{fd} - e'_q - (x_d - x'_d)\, i_d)/T'_{do}$$

$$e'_d = (- e'_d + (x_q - x'_q)\, i_q)/T'_{qo}$$

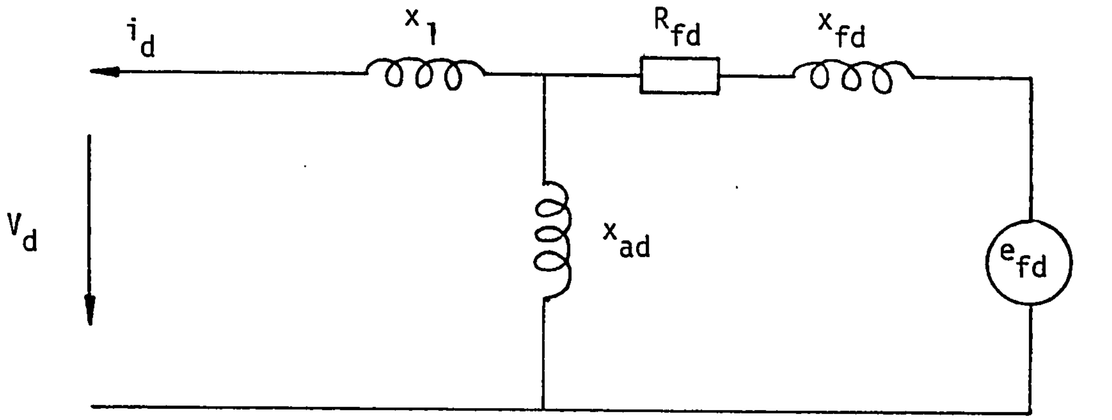
$$V_q = e'_q - x'_d i_d - R_a i_q \qquad \text{(A-1)}$$

$$V_d = e'_d + x'_q i_q - R_a i_d$$

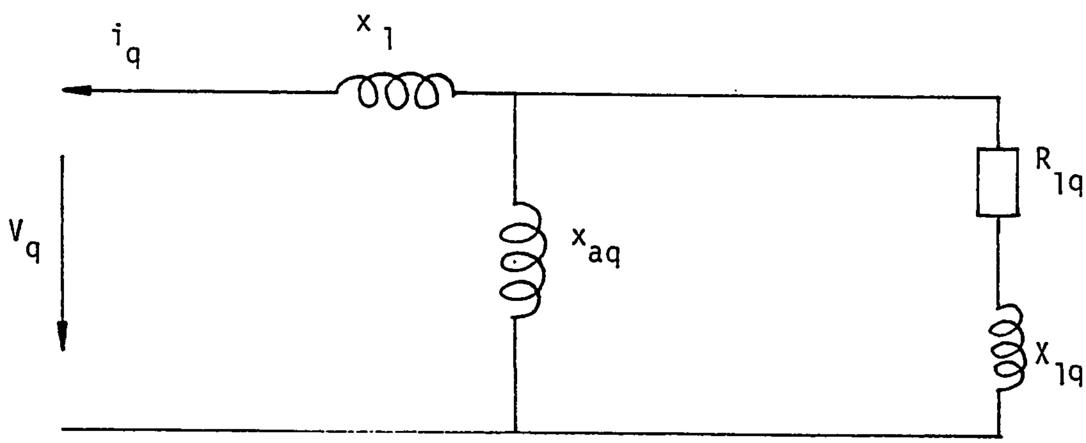
Same equation in the Laplace form (neglecting losses in the armature)

$$i_d = \frac{-(1+ST'_{do})}{x_d+Sx'_d T'_{d0}} V_q + \frac{Ke_{fd}}{x_d+Sx'_d T'_{d0}}$$

$$i_q = \frac{(1+ST'_{qo})}{x_q+Sx'_q T'_{qo}} \qquad \text{(A-2)}$$



d - axis



q-axis

i_d Component in direct axis of P.U.Stator Current

i_q Component in quadrature axis of P.U.Stator Current

V_d Component in direct axis of P.U. terminal voltage

V_q Component in quadrature axis of P.U.terminal voltage

Figure A-1 Two-Axix Model of the Synchronous Machine.

In Matrix Form:

$$\begin{bmatrix} i_d \\ \\ i_q \end{bmatrix} = \begin{bmatrix} 0 & Y_{dq} \\ \\ Y_{qd} & 0 \end{bmatrix} + \begin{bmatrix} Y_{df} \\ \\ 0 \end{bmatrix} e_{fd} \qquad \text{(A-3)}$$

where the position of the reference axis q with respect to the direction of the terminal voltage is the rotor internal angle δ (Figure A-2).

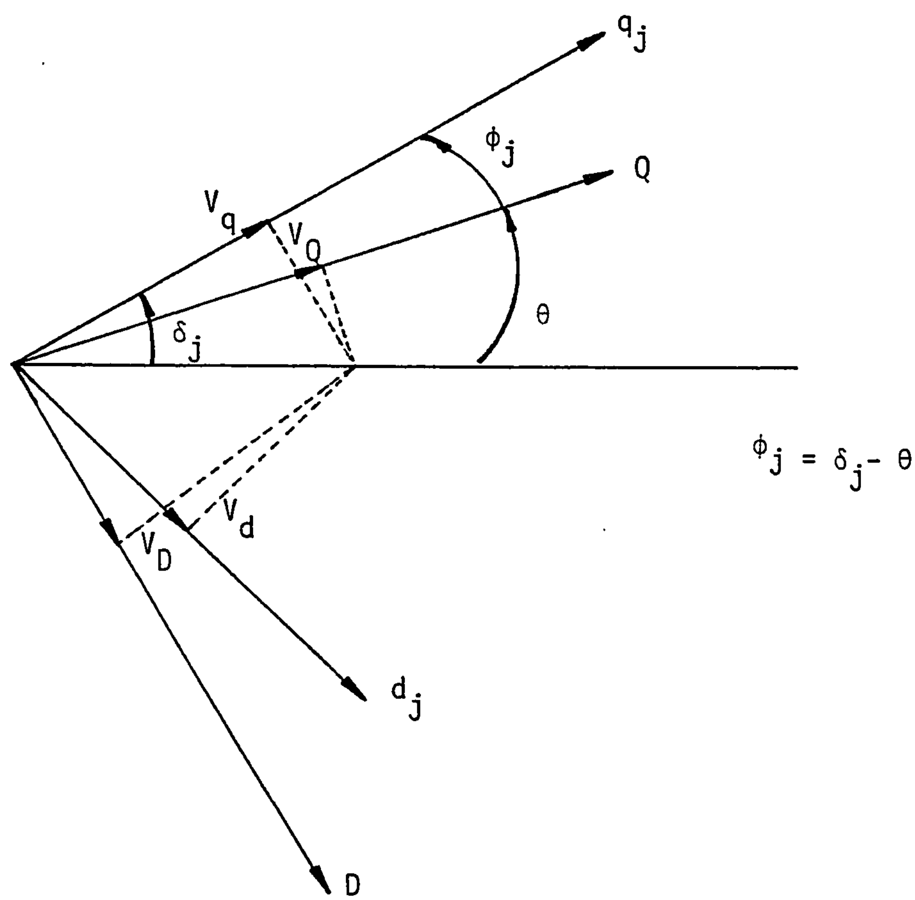
$$Y_{dq} = \frac{-(1+ST'_{do})}{x_d+Sx'_d\, T'_{d0}}$$

$$Y_{qd} = \frac{(1+ST'_{q0})}{x_d+Sx'_d\, T'_{q0}} \qquad \text{(A-4)}$$

$$Y_{df} = \frac{K}{x_d+Sx'_d\, T'_{d0}}$$

The equation of each machine of a coherent group can be rewritten in terms of the components (i_{Dj}, i_{Qj}) of its current and (V_{Dj}, V_{Qj}) of its terminal voltage on a common pair of axes, D and Q. The direction of the axis Q with respect to the terminal voltage is being denoted as Θ, and $\phi_j = (\delta_j - \Theta)$ is the position of the axis q with respect to axis Q as shown on Figure A-2.

For a machine denoted by subscript j, this transformation reads:



$$V_D = V_d \operatorname{Cos}\phi - V_q \operatorname{Sin}\phi$$

$$V_Q = V_d \operatorname{Sin}\phi + V_q \operatorname{Cos}\phi$$

Figure A-2 Defination of Reference Axes.

$$\begin{bmatrix} i_{Dj} \\ i_{Qj} \end{bmatrix} = \begin{bmatrix} T_j \end{bmatrix} \begin{bmatrix} 0 & Y_{dqj} \\ Y_{qdj} & 0 \end{bmatrix} \begin{bmatrix} T_j^t \end{bmatrix} + \begin{bmatrix} T_j \end{bmatrix} \begin{bmatrix} Y_{dfj} \\ 0 \end{bmatrix} e_{fdj} \tag{A-5}$$

where

$$[T_j] = \begin{bmatrix} \cos \Phi_j & -\sin \Phi_j \\ \sin \Phi_j & \cos \Phi_j \end{bmatrix}$$

and $[T_j^t]$ is the transpose of $[T_j]$.

Since the terminal voltage is identical for each machine of the coherent group, each of these machine has the same component V_{Dj}, respectively V_{Qj}, when projected on the same axis.

Equation (A-5) can thus be summed to obtain the components of the total current:

$$\begin{bmatrix} \Sigma i_{Dj} \\ \\ \Sigma i_{Qj} \end{bmatrix} = \Sigma_j \begin{bmatrix} \\ T_j \\ \\ \end{bmatrix} \begin{bmatrix} 0 & Y_{dqj} \\ \\ Y_{qdj} & 0 \end{bmatrix} \begin{bmatrix} \\ T_j^t \\ \\ \end{bmatrix} \begin{bmatrix} V_D \\ \\ V_Q \end{bmatrix}$$

$$+ \begin{bmatrix} \\ T_j \\ \\ \end{bmatrix} \begin{bmatrix} Y_{dfj} \\ \\ 0 \end{bmatrix} e_{fdj} \qquad \text{(A-6)}$$

which can be rewritten as:

$$\begin{bmatrix} \Sigma i_D \\ \\ \Sigma i_Q \end{bmatrix} = \begin{bmatrix} Y_{DD} & Y_{DQ} \\ \\ Y_{QD} & Y_{QQ} \end{bmatrix} \begin{bmatrix} V_D \\ \\ V_Q \end{bmatrix} + \begin{bmatrix} Y_{DF} \\ \\ Y_{QF} \end{bmatrix} e_{FD} \qquad \text{(A-7)}$$

with

$$Y_{DD} = \sum_j - (Y_{dqj} + Y_{qdj}) \operatorname{Sin} \phi_j \operatorname{Cos} \phi_j$$

$$Y_{DQ} = \sum_j Y_{dqj} \cos^2 \phi_j - Y_{qdj} \operatorname{Sin}^2 \phi_j$$

$$Y_{QD} = \sum_j - Y_{dqj} \operatorname{Sin}^2 \phi_j + Y_{qdj} \operatorname{Cos}^2 \phi_j \qquad \text{(A-8)}$$

$$Y_{QQ} = - Y_{DD}$$

$$Y_{DF} \cdot e_{FD} = \sum_j Y_{dfj} \operatorname{Cos} \phi_j \, e_{fdj}$$

$$Y_{QF} \cdot e_{FD} = \sum_j Y_{dfj} \operatorname{Sin} \phi_j \, e_{fdj}$$

For Equation (A-7) to represent a two-axes synchronous machine, it is necessary to choose the angle Θ such that Y_{QF} and the diagonal elements Y_{DD} and Y_{QQ} vanish.

The appropriate angle Θ is calculated as follows:

Assume the admittances of Equation (A-8) have been calculated for an arbitrary angle Θ, (e.g., Θ = 0), and the axes D and Q are rotated clockwise by an angle ΔΘ. After this transformation, the operational admittance matrix Equation (A-7) projected on the new axes is:

$$\begin{bmatrix} Y'_{DD} & Y'_{DQ} \\ Y'_{QD} & Y'_{QQ} \end{bmatrix} = \begin{bmatrix} T' \end{bmatrix} \begin{bmatrix} Y_{DD} & Y_{DQ} \\ Y_{QD} & Y_{QQ} \end{bmatrix} \begin{bmatrix} T'^{t} \end{bmatrix} \quad \text{(A-9)}$$

with $$\begin{bmatrix} T' \end{bmatrix} = \begin{bmatrix} \operatorname{Cos}\Delta\Theta & \operatorname{Sin}\Delta\Theta \\ -\sin\Delta\Theta & \operatorname{Cos}\Delta\Theta \end{bmatrix}$$

Taking into account that $Y_{QQ} = -Y_{DD}$, it follows that:

$$Y'_{DD} = Y_{DD}(\mathrm{Cos}^2\Delta\Theta - \sin^2\Delta\Theta) + (Y_{DQ}+Y_{QD})\sin\Delta\Theta\ \mathrm{Cos}\ \Delta\Theta \qquad \text{(A-10)}$$

$$\text{and } Y_{DD}' = -Y_{QQ}' = 0 \text{ if } \tan\Delta\Theta = \frac{-2Y_{DD}}{Y_{DQ}+Y_{QD}} \qquad \text{(A-11)}$$

Since the admittance Y_{DD}, Y_{QQ}, Y_{DQ} and Y_{QD} are frequency dependent, this condition and the condition $Y_{QF} = 0$ can only be approximated. A good approximation was found when Equation (A-11) is satisfied for $S \rightarrow j\infty$.

The operational admittances Y'_{DQ} and Y'_{QD} of Equation (A-9) are then calculated in the prescribed frequency range. The operational admittance of the equivalent machine, expressed in function of the equivalent parameter, read as:

$$Y^*_{DD} = 0$$

$$Y_{DQ}{}^* = \frac{-(1+ST'^*_{D0})}{x^*_D + Sx'^*_D\, T'^*_{D0}}$$

$$Y^*_{QD} = \frac{1+ST'^*_{Q0}}{x^*_Q + Sx'^*_Q\, T'^*_{Q0}} \qquad \text{(A-12)}$$

$$Y^*_{QQ} = 0$$

$$Y^*_{DF} = \frac{-K^*}{x^*_D + Sx'^*_D T'^*_{D0}}$$

$$Y^*_{QF} = 0$$

x^*_D, x'^*_D, T'^*_{D0} are obtained by least-square fit of Y^*_{DQ} with Y'_{DQ}.

x^*_Q, x'^*_Q, T'^*_{Q0} are obtained by least-square fit of Y^*_{QD} with Y'_{QD}.

A-2. EQUIVALENT MACHINE SATURATION

It is prescribed that, at no-load:

$$i_{FD} = \Sigma\, i_{fd}$$

or $$\frac{E_a}{X^*_{ad}}(1 + S^*) = \sum_j \frac{E_a}{X_{adj}}(1 + S_j)$$

APPENDIX B

REDUCTION OF GENERATOR BUSES

The coherency based reduction of generator buses consists of four basic steps. In addition, a fifth step can be performed optionally in order to obtain further simplification but with some loss in accuracy. Each of the steps is described in turn below. The example network in Figure B-1 is used to illustrate the procedure; consider that the generator terminal buses 1, 2 and 3 have been identified as coherent and are to be replaced by a single equivalent bus 4.

Step 1:

The voltage $\tilde{V}_t$ in the equivalent bus is defined; either an average voltage of the group or the voltage of an individual bus is selected. Each terminal bus is connected through an ideal transformer with complex turns ratio to the equivalent bus. The turns ratio is directed as shown in Figure B-2 and is calculated as: $\tilde{a}_k = \tilde{V}_k/\tilde{V}_t$ where: $\tilde{V}_k$ = voltage on bus k.

Under coherent conditions, the ratio $\tilde{a}_k$ is constant for each bus in the group and no circulating power flows through any of the phase shifters. It follows that the introduction of the phase shifters will have no effect on the response of the network voltages and currents under these conditions. The situation described is analogous to the well known method for simplifying d.c. networks, where a short circuit is introduced between two nodes which always have the same d.c. voltage.

Step 2:

The generator terminal buses will generally be connected radially through a step-up transformer to the rest of the network. However, in some cases the low voltage bus may have been eliminated by combining the transformer reactance with the generator internal reactance. In this circumstance several non-radial buses may be included within the coherent group and a common branch may connect them. (e.g., the branch between buses 2 and 3 in Figure B-2). The function of the second step is to detect this situation and to remove the intragroup branch by replacing it by equivalent shunt admittances. To explain this, consider the current flow in the branch between buses 2 and 3:

$$\tilde{I}_{23} = (\tilde{V}_2 - \tilde{V}_3)\,\tilde{Y}_{23}$$

Since $\tilde{V}_2/\tilde{V}_3$ is constant the current can be expressed as a linear function of either $\tilde{V}_2$ or $\tilde{V}_3$. The effect of the branch can thus be replaced by a shunt admittance $(1 - \tilde{V}_3/\tilde{V}_2)\,\tilde{Y}_{23}$ at bus 2 and a shunt admittance $(1 - \tilde{V}_2/\tilde{V}_3)\,\tilde{Y}_{23}$ at bus 3.

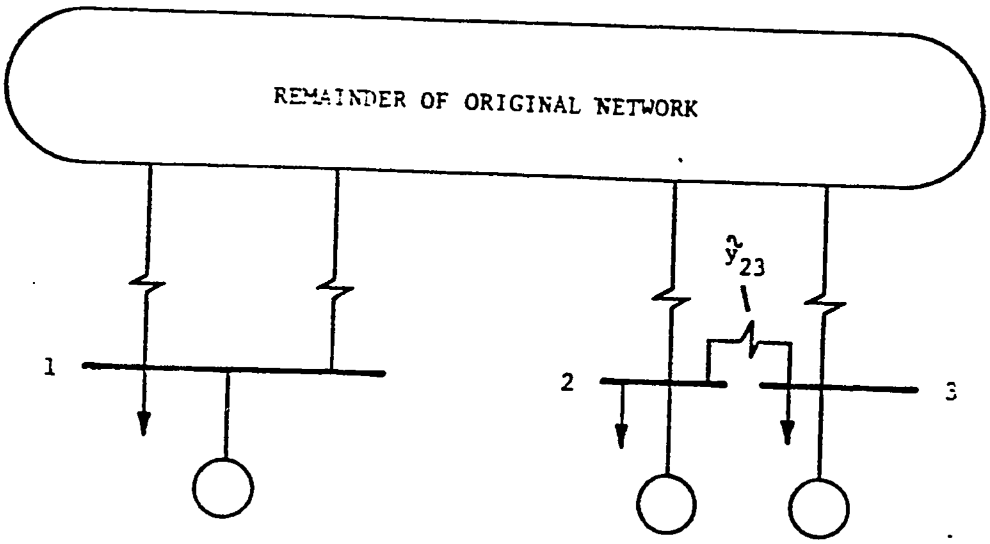


Figure B-1. Configuration of Coherent Generator Buses in Original Network

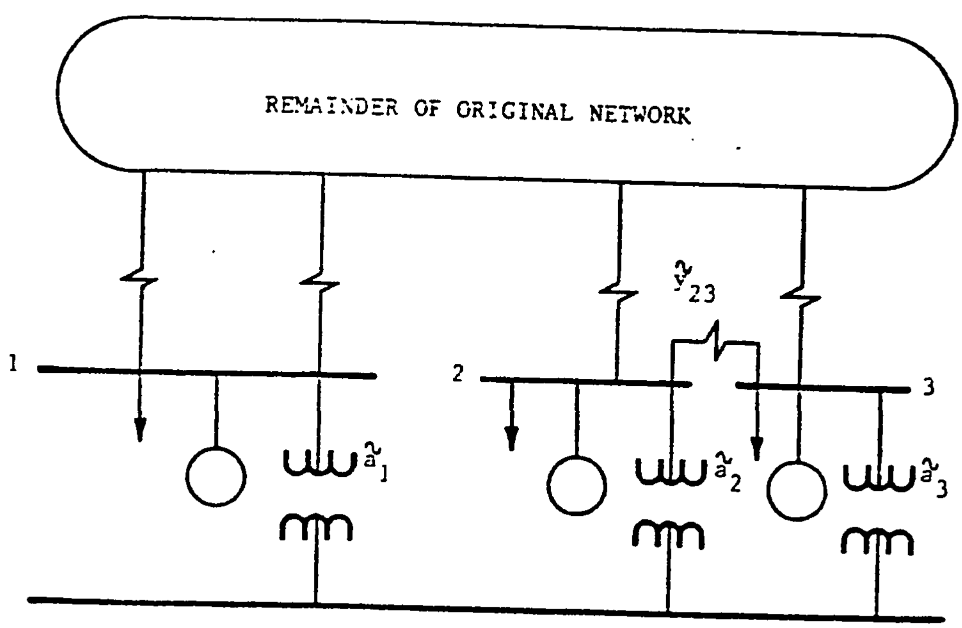


Figure B-2. Coherent Generator Buses are Connected to an Equivalent Bus Through Ideal Transformers with Complex Ratio

Figure B-3 shows the configuration after the intragroup branch has been removed from the example network.

Step 3:

The generation, load and shunt admittances on the coherent buses are transferred and summed on the equivalent bus as illustrated in Figure B-4. The generation and load are not modified by the transfer. The shunt admittance is scaled to account for the off-nominal tap ratio of the ideal transformer. If a non-linear load representation is used then the constant MVA, constant current and constant impedance load components are transferred individually and kept separate.

Step 4:

The original coherent buses are eliminated by series combination of the original branch and the ideal transformer (see Figure B-5). If several original branches connect to the eliminated bus, (as for bus 1), the ideal transformer is combined with each of them.

Step 5:

This step is an optional one in which the phase shifts in the ideal transformers are replaced by compensating shunt admittances. These shunt

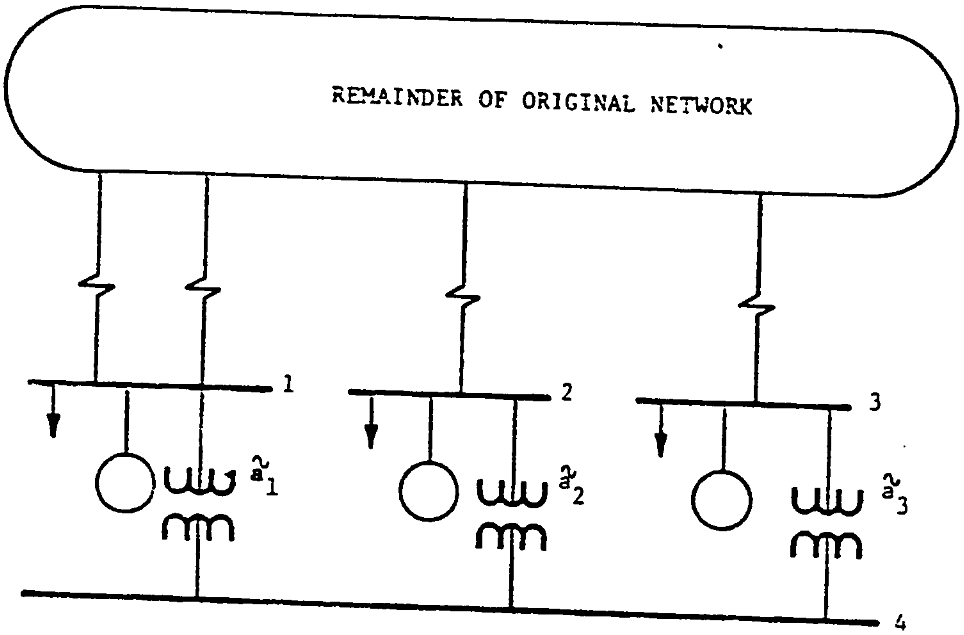


Figure B-3. Branch Between Coherent Buses 2 and 3 is Replaced by Equivalent Shunt Admittance on Buses 2 and 3

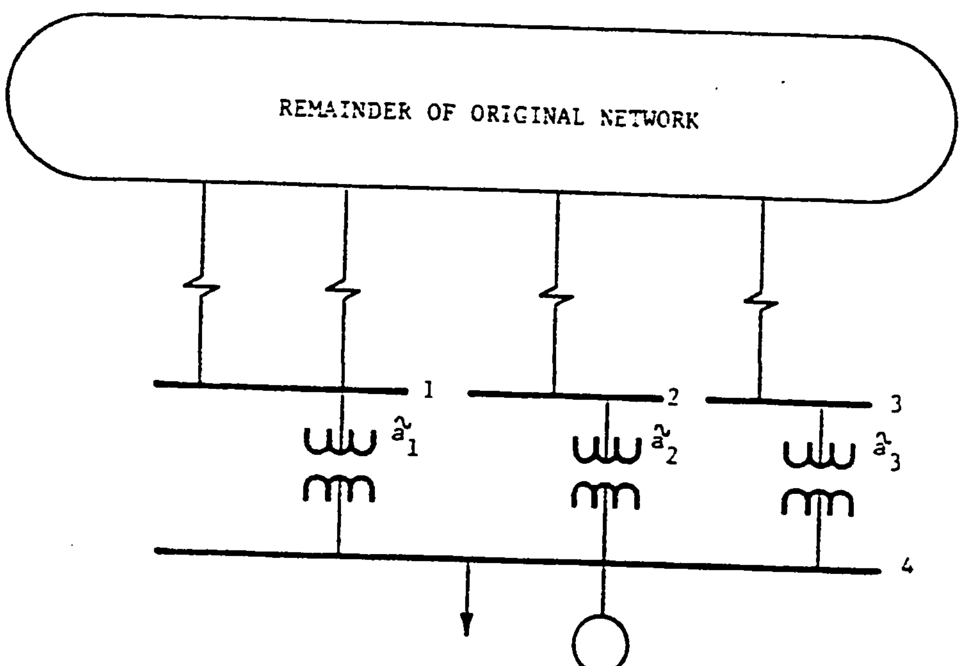


Figure B-4. Generation, Loads and Shunt Admittances on Original Buses are Transferred to the Equivalent Bus

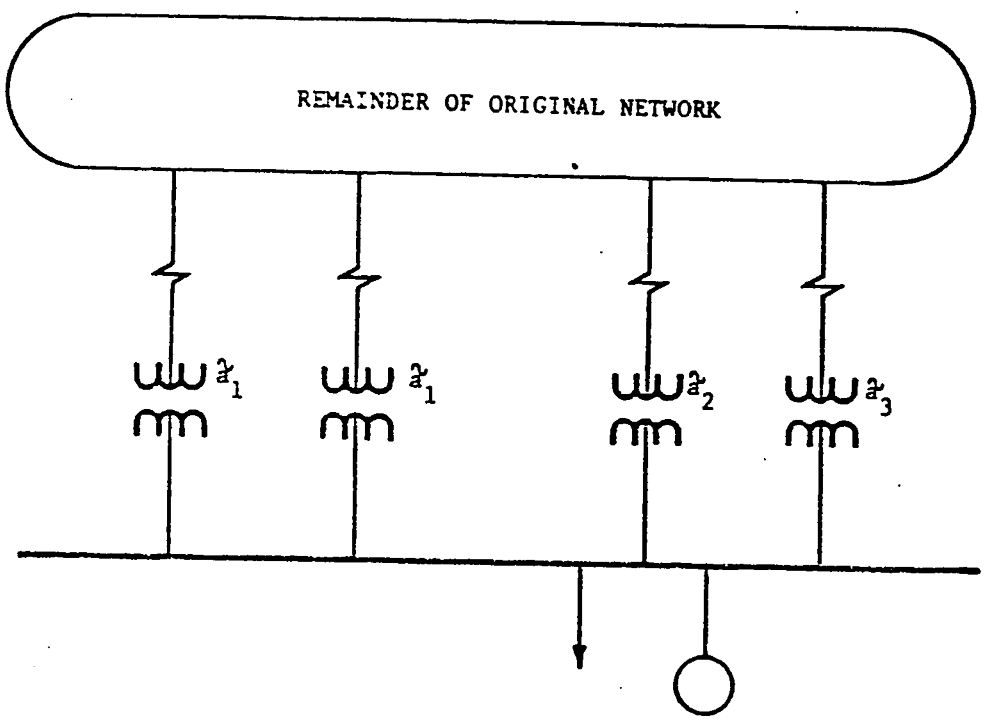


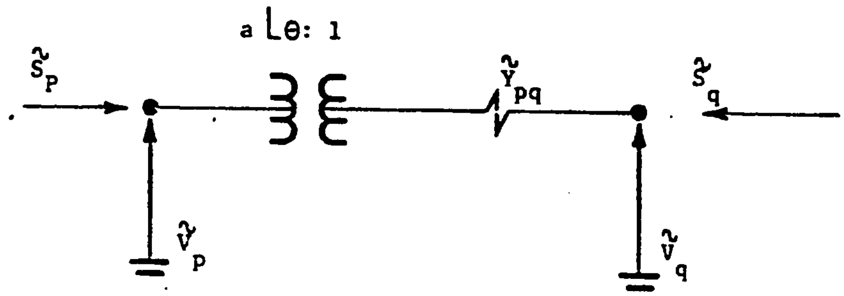
Figure B-5 Original Generator Terminal Buses are Eliminated by Series Combination of Ideal Transformers with Original Branches admittances are calculated so that the power flows from buses at the ends of the branch are preserved. Figure B-6 illustrates the conversion and the required values of the compensating admittances. The new network is an approximation as the voltages deviate from the base case load flow condition. However, this step has been useful for accommodating the equivalent within transient stability programs which do not represent phase shifters.

It is clear that the reduction procedure only affects those branches which are connected to buses in the coherent group. The balanced load flow condition on the original buses is preserved and a balanced load flow condition is created for the equivalent bus.

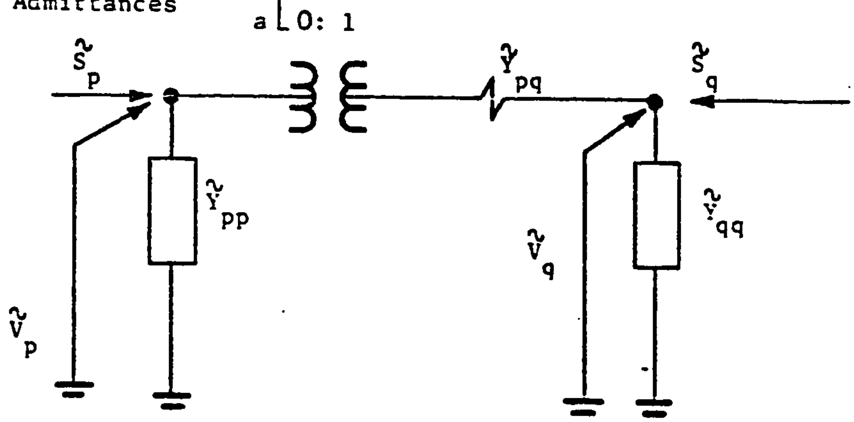
The accuracy of the equivalent network which is produced at Step 4 is not affected by the choice of the equivalent voltage $\tilde{V}_t$. However, the phase shifts which are introduced into the equivalent lines are directly related to the angle of $\tilde{V}_t$. Consequently, the selection of $\tilde{V}_t$ will affect the accuracy of any network in which these phase shifts are approximated using Step 5.

The internal voltages of the machines (e.g., quadrature axis transient voltages, field voltage) depend upon the magnitude of $\tilde{V}_t$. The magnitude of $\tilde{V}_t$ is defined as an average of the original bus voltages with the aim of minimizing the variation in the internal machine voltages which occurs as a result of the machines being transferred to the equivalent bus.

(a) Branch with Phase Shifter



(b) Branch with Phase Shifter Approximated by Shunt Admittances



$$\tilde{Y}_{pp} = \tilde{V}_q/\tilde{V}_p\ (1/a\angle 0 - 1/a\angle\theta)^{*}\tilde{Y}_{pq}$$

$$\tilde{Y}_{qq} = \tilde{V}_p/\tilde{V}_q\ (1/a\angle 0 - 1/a\angle\theta)\tilde{Y}_{pq}$$

Figure B-6 Illustration of Phase Shifter Approximation

The connection of the generator terminal buses to the equivalent bus through the ideal transformers introduces an infinitely strong synchronizing ties between them. For this reason, it is preferable if the coherency-based reduction is performed on the generator low voltage buses in order that the effect of this artificial tie, as seen from the rest of the network, be minimized by the relatively high transformer reactances.

APPENDIX C

```
$JOB
C        ******************************************************
C        *                                                    *
C        *             PARAMETER ESTIMATION PROGRAM           *
C        *                                                    *
C        ******************************************************
C
C
C        MAIN LINE PROGRAM FOR SUBROTINE BSOLVE
         DIMENSION P(900),A(10,12),AC(10,12),X(200),
        $B(10),Z(200),Y(200),BV(10),BMIN(10),BMAX(10),XX(200)
         REAL T3(9),T4(9),T5(9),T6(9),KHP(9),KIP(9),KLP(9),R1(9),
        $KSH(9),M(9),AV(9),SIT(9),PMB(9),W(9,200)
         COMPLEX AT(9,200),C(9,200),D(9,200),E(9,200),A1(200),C1(200),
        $D1(200),E1(200),Z1(9,200)
         COMMON KK,NN,PH,FNU,FLA,TAU,EPS,PHMIN,I,ICON,FV,DV,KD,GAMM
         EXTERNAL FUNC
C
         READ(5,*) N1
         READ(5,*) (T3(K),K=1,N1)
         READ(5,*) (T4(K),K=1,N1)
         READ(5,*) (T5(K),K=1,N1)
         READ(5,*) (T6(K),K=1,N1)
         READ(5,*) (KHP(K),K=1,N1)
         READ(5,*) (KIP(K),K=1,N1)
         READ(5,*) (KLP(K),K=1,N1)
         READ(5,*) (R1(K),K=1,N1)
         READ(5,*) (KSH(K),K=1,N1)
         READ(5,*) (M(K),K=1,N1)
         READ(5,*) (AV(K),K=1,N1)
         READ(5,*) (SIT(K),K=1,N1)
         READ(5,*) (PMB(K),K=1,N1)
C
         NI=5
         NO=6
C
C        READ IN NUMBER OF DATA POINTS,UNKNOWNS.
C
         READ (NI,*) NN,KK
C011     FORMAT (8I10)
C
C        READ IN INITIAL GUESSES.
C
         READ (NI,*) (B(J),J=1,KK)
C012     FORMAT(8E10.4)
C
C        READ IN LIMIT ON VARIABLES.
C
         READ (NI,*) (BMIN(J),J=1,KK)
         READ (NI,*) (BMAX(J),J=1,KK)
C
C        READ IN INDEPENDENT VARIABLES.
C        READ IN DEPENDENT VARIABLES.
C
         CALL SUMGT(T3,T4,T5,T6,KHP,KIP,KLP,R1,KSH,M,AV,SIT,PMB,
        $X,Y,N1)
C
         FNU=0.0
         FLA=0.0
         TAU=0.0
         EPS=0.0
         PHMIN=0.0
         I=0
```

```
      KD=KK
      FV=0.0
      DO 100 J=1,KK
      BV(J)=1
  100 CONTINUE
      ICON=KK
      ITER=0
      WRITE (NO,015)
  015 FORMAT (1H1,10X,27HBSOLVE REGRESSION ALGORITHM )
C
  200 CALL BSOLVE(B, Z, X, Y, BV, BMIN, BMAX, P, FUNC, A, AC)
C
      ITER=ITER+1
      WRITE (NO,001) ICON,PH,ITER
  001 FORMAT (/,2X,6HICON= ,I3,4X, 5HPH = ,E15.8,16HITERATION NO. =
     1 ,I3)
      IF (ICON) 10, 300, 200
   10 IF (ICON+1)  20, 60, 200
   20 IF (ICON+2)  30, 70, 200
   30 IF (ICON+3)  40, 80, 200
   40 IF (ICON+4)  50, 90, 200
   50 GO TO 95
   60 WRITE (NO,004)
  004 FORMAT (//,2X,32HNO FUNCTION IMPROVEMENT POSSIBLE )
      GO TO 300
   70 WRITE (NO,005)
  005 FORMAT(//,2X, 28HMORE UNKNOWNS THAN FUNCTIONS)
      GO TO 300
   80 WRITE (NO,006)
  006 FORMAT (//,2X, 24HTOTAL VARIABLES ARE ZERO)
   90 WRITE (NO,007)
  007 FORMAT (//,2X,80HCORRECTIONS SATISFY CONVERGENCE REQUIREMENTS BUT
     1LAMBDA FACTOR (FLA) STILL LARGE)
      GO TO 300
   95 WRITE (NO,008)
  008 FORMAT (//,2X, 20HTHIS IS NOT POSSIBLE)
      GO TO 300
  300 WRITE (NO,002)
  002 FORMAT (//,2X, 26HSOLUTIONS OF THE EQUATIONS)
      DO 400 J=1,KK
      WRITE (NO,003) J, B(J)
  003 FORMAT (/,2X, 2HB(,I2,4H) = ,E16.8)
  400 CONTINUE
 1000 STOP
      END
C
C
C
C
C
C

      SUBROUTINE FUNC (KK, B, NN, Z, X)
C
      DIMENSION X(200), Z(200), B(10),XX(200)
      COMPLEX A1(200),C1(200),D1(200),E1(200)
      DO 100 JJ=1,NN
      XX(JJ)=0.4218285*X(JJ)
      A1(JJ)=CMPLX(1.0,XX(JJ))
      C1(JJ)=CMPLX(1.0,B(1)*X(JJ))
      D1(JJ)=CMPLX(1.0,B(2)*X(JJ))
      E1(JJ)=CMPLX(1.0,B(3)*X(JJ))
      Z(JJ)=CABS((((0.3095*D1(JJ)*E1(JJ))+(0.202*E1(JJ))+0.488)*
```

```
     $(840.0*(-1.0)))/(0.05*(1.0+2.0*0.08*0.7*0.7)*A1(JJ)*C1(JJ)*
     $D1(JJ)*E1(JJ)*100.0))
  100 CONTINUE
C
      RETURN
      END
C
C
C
C
C
      SUBROUTINE BSOLVE ( B, Z, X, Y, BV, BMIN, BMAX, P, FUNC, A, AC)
C
C
      COMMON KK,NN,PH,FNU,FLA,TAU,EPS,PHMIN,I,ICON,FV,DV,KD,GAMM
      DIMENSION B(10),Z(200),Y(200),BV(10),BMIN(10),BMAX(10),
     $P(900),A(10,12),AC(10,12),X(200)
C
      K=KK
      N=NN
      KP1=K+1
      KP2=KP1+1
      KBI1=K*N
      KBI2=KBI1+K
      KZI=KBI2+K
      IF( FNU .LE. 0. ) FNU = 10.0
      IF( FLA .LE. 0. ) FLA = 0.01
      IF( TAU .LE. 0. ) TAU = 0.001
      IF( EPS .LE. 0. ) EPS = 0.00002
      IF(PHMIN.LE.0.) PHMIN=0.
  120 KE=0
  130 DO 160 I1=1,K
  160 IF( BV(I1) .NE. 0. ) KE=KE+1
      IF(KE .GT. 0 ) GO TO 170
  162 ICON= -3
  163 GO TO 2120
  170 IF(N .GE. KE ) GO TO 500
  180 ICON= -2
  190 GO TO 2120
  500 I1=1
  530 IF( I .GT. 0 ) GO TO 1530
  550 DO 560 J1=1,K
      J2=KBI1+J1
      P(J2)=B(J1)
      J3=KBI2+J1
  560 P(J3) = ABS(B(J1)) + 1.0E-02
      GO TO 1030
  590 IF(PHMIN .GT. PH .AND. I .GT. 1) GO TO 625
      DO 620 J1=1,K
      N1 = (J1-1)*N
      IF( BV(J1) ) 601,620,605
  601 CONTINUE
      IF( JTEST .NE. (-1) ) GO TO 620
      BV(J1)=1.0
  605 DO 606 J2=1,K
      J3=KBI1+J2
  606 P(J3)=B(J2)
      J3=KBI1+J1
      J4=KBI2+J1
      DEN = 0.001*AMAX1(P(J4),ABS(P(J3)))
      IF (P(J3) + DEN .LE. BMAX(J1)) GO TO 55
      P(J3) =P(J3) - DEN
```

```
      DEN = - DEN
      GO TO 56
   55 P(J3) =P(J3) + DEN
   56 CALL FUNC (K, P(KBI1+1), N, P(N1+1), X)
      DO 610 J2=1,N
      JB=J2+N1
  610 P(JB) =(P(JB) -Z(J2))/DEN
  620 CONTINUE
C
C     SET UP CORRECTION EQUATIONS
C
  625 DO 725 J1=1,K
      N1 = (J1-1)*N
      A(J1,KP1)=0.
      IF( BV(J1) ) 630,692,630
  630 DO 640 J2=1,N
      N2=N1+J2
  640 A(J1,KP1)=A(J1,KP1) + P(N2)*(Y(J2)-Z(J2))
  650 DO 680 J2=1,K
  660 A(J1,J2)=0.
  665 N2=(J2-1)*N
  670 DO 680 J3=1,N
  672 N3=N1+J3
  674 N4=N2+J3
  680 A(J1,J2)=A(J1,J2)+P(N3)*P(N4)
      IF(A(J1,J1).GT.1.E-20) GO TO 725
  692 DO 694 J2=1,KP1
  694 A(J1,J2)=0.
  695 A(J1,J1)=1.0
  725 CONTINUE
      GN=0.
      DO 729 J1=1,K
  729 GN=GN+A(J1,KP1)**2
C
C     SCALE CORRECTION EQUATIONS
C
      DO 726 J1=1,K
  726 A(J1,KP2) = SQRT(A(J1,J1))
      DO 727 J1=1,K
      A(J1,KP1)=A(J1,KP1)/A(J1,KP2)
      DO 727 J2=1,K
  727 A(J1,J2)=A(J1,J2)/(A(J1,KP2)*A(J2,KP2))
  730 FL=FLA/FNU
      GO TO 810
  800 FL = FNU*FL
  810 DO 840 J1=1,K
  820 DO 830 J2=1,KP1
  830 AC(J1,J2)=A(J1,J2)
  840 AC(J1,J1)=AC(J1,J1)+FL
C
C     SOLVE CORRECTION EQUATIONS
C
      DO 930 L1=1,K
      L2=L1+1
      DO 910 L3=L2,KP1
  910 AC(L1,L3)=AC(L1,L3)/AC(L1,L1)
      DO 930 L3=1,K
      IF(L1-L3) 920,930,920
  920 DO 925 L4=L2,KP1
  925 AC(L3,L4)=AC(L3,L4)-AC(L1,L4)*AC(L3,L1)
  930 CONTINUE
C
      DN=0.
```

```
      DG=0.
      DO 1028 J1=1,K
      AC(J1,KP2)=AC(J1,KP1)/A(J1,KP2)
      J2=KBI1+J1
      P(J2) = AMAX1(BMIN(J1),AMIN1(BMAX(J1),B(J1)+AC(J1,KP2)))
      DG    = DG  +AC(J1,KP2)  * A(J1,KP1) * A(J1,KP2)
      DN =DN +AC(J1,KP2)*AC(J1,KP2)
 1028 AC(J1,KP2)=P(J2)-B(J1)
      COSG =DG/SQRT(DN*GN)
      JGAM =0
      IF( COSG ) 1100,1110,1110
 1100 JGAM = 2
      COSG = - COSG
 1110 CONTINUE
            COSG = AMIN1(COSG,1.0)
      GAMM= ARCOS(COSG)*180./(3.14159265)
      IF( JGAM .GT. 0 ) GAMM = 180. - GAMM
 1030 CALL FUNC (K, P(KBI1+1), N, P(KZI+1), X)
 1500 PHI = 0.
      DO 1520 J1=1,N
      J2=KZI+J1
 1520 PHI=PHI+(P(J2)-Y(J1))**2
      IF(PHI.LT. 1.E-10) GO TO 3000
      IF(I .GT. 0) GO TO 1540
 1521 ICON=K
      GO TO 2110
 1540 IF(PHI .GE. PH) GO TO 1530
C
C     EPSILON TEST
C
 1200 ICON=0
      DO 1220 J1=1,K
      J2=KBI1+J1
 1220 IF( ABS(AC(J1,KP2))/(TAU + ABS(P(J2))) .GT. EPS ) ICON =ICON+1
      IF(ICON .EQ. 0 ) GO TO 1400
C
C     GAMMA LAMBDA TEST
C
      IF(FL .GT. 1.0 .AND. GAMM .GT.90.0) ICON = -1
      GO TO 2105
C
C     GAMMA EPSILON TEST
C
 1400 IF(FL .GT. 1.0 .AND. GAMM .LE. 45.0) ICON = -4
      GO TO 2105
C
 1530 IF(I1-2) 1531,1531,2310
 1531 I1=I1+1
      GO TO (530,590,800),I1
 2310 IF(FL .LT. 1.0E+8 ) GO TO 800
 1320 ICON= -1
C
 2105 FLA=FL
      DO 2091 J2=1,K
      J3=KBI1+J2
 2091 B(J2) = P(J3)
 2110 DO 2050 J2=1,N
      J3=KZI+J2
 2050 Z(J2)=P(J3)
      PH=PHI
      I=I+1
 2120 RETURN
 3000 ICON=0
```

```
      DG=0.
      DO 1028 J1=1,K
      AC(J1,KP2)=AC(J1,KP1)/A(J1,KP2)
      J2=KBI1+J1
      P(J2) = AMAX1(BMIN(J1),AMIN1(BMAX(J1),B(J1)+AC(J1,KP2)))
      DG     = DG   +AC(J1,KP2)   * A(J1,KP1) * A(J1,KP2)
      DN =DN +AC(J1,KP2)*AC(J1,KP2)
 1028 AC(J1,KP2)=P(J2)-B(J1)
      COSG =DG/SQRT(DN*GN)
      JGAM =0
      IF( COSG ) 1100,1110,1110
 1100 JGAM = 2
      COSG = - COSG
 1110 CONTINUE
              COSG = AMIN1(COSG,1.0)
      GAMM= ARCOS(COSG)*180./(3.14159265)
      IF( JGAM .GT. 0 ) GAMM = 180. - GAMM
 1030 CALL FUNC (K, P(KBI1+1), N, P(KZI+1), X)
 1500 PHI = 0.
      DO 1520 J1=1,N
      J2=KZI+J1
 1520 PHI=PHI+(P(J2)-Y(J1))**2
      IF(PHI.LT. 1.E-10) GO TO 3000
      IF(I .GT. 0) GO TO 1540
 1521 ICON=K
      GO TO 2110
 1540 IF(PHI .GE. PH) GO TO 1530
C
C     EPSILON TEST
C
 1200 ICON=0
      DO 1220 J1=1,K
      J2=KBI1+J1
 1220 IF( ABS(AC(J1,KP2))/(TAU + ABS(P(J2))) .GT. EPS ) ICON =ICON+1
      IF(ICON .EQ. 0 ) GO TO 1400
C
C     GAMMA LAMBDA TEST
C
      IF(FL .GT. 1.0 .AND. GAMM .GT.90.0) ICON = -1
      GO TO 2105
C
C     GAMMA EPSILON TEST
C
 1400 IF(FL .GT. 1.0 .AND. GAMM .LE. 45.0) ICON = -4
      GO TO 2105
C
 1530 IF(I1-2) 1531,1531,2310
 1531 I1=I1+1
      GO TO (530,590,800),I1
 2310 IF(FL .LT. 1.0E+8 ) GO TO 800
 1320 ICON= -1
C
 2105 FLA=FL
      DO 2091 J2=1,K .
      J3=KBI1+J2
 2091 B(J2) = P(J3)
 2110 DO 2050 J2=1,N
      J3=KZI+J2
 2050 Z(J2)=P(J3)
      PH=PHI
      I I+1
 2120 RETURN
 3000 ICON=0
```

```
      GO TO 2105
C
      END
C
C
C
C
C


      FUNCTION ARCOS(Z)
C
      X=Z
      KEY=0
      IF( X.LT. (-1.)) X=-1.
      IF( X.GT. 1.) X=1.
      IF( X.GE. (-1.) .AND. X .LT. 0.) KEY=1
      IF( X.LT. 0.) X=ABS(X)
      IF( X.EQ. 0.) GO TO 10
      ARCOS=ATAN (SQRT(1.-X*X)/X)
      IF( KEY .EQ. 1) ARCOS=3.14159265-ARCOS
      GO TO 999
   10 ARCOS=1.5707963
C
  999 RETURN
      END
C
C
C     SUBROUTINE TO CALCULATE THE TRANSFER FUNCTION FOR
C     INDIVIDUAL GOVERNOR TURBINE MODEL FOR DISCREET
C                    VALUE OF FREQUENCY
C
C


      SUBROUTINE SUMGT(T3,T4,T5,T6,KHP,KIP,KLP,R1,KSH,M,AV,SIT,PMB,
     $X,Y,N)
C
      REAL T3(9),T4(9),T5(9),T6(9),KHP(9),KIP(9),KLP(9),R1(9),
     $KSH(9),M(9),AV(9),SIT(9),PMB(9),W(9,200),X(200),Y(200)
      COMPLEX AT(9,200),C(9,200),D(9,200),E(9,200),Z1(9,200)
      I=1
 5    J=1
      W(I,J)=0.1
 10   AT(I,J)=CMPLX(1.0,T3(I)*W(I,J))
      C(I,J)=CMPLX(1.0,T4(I)*W(I,J))
      D(I,J)=CMPLX(1.0,T5(I)*W(I,J))
      E(I,J)=CMPLX(1.0,T6(I)*W(I,J))
      Z1(I,J)=((((KHP(I)*D(I,J)*E(I,J))+(KIP(I)*E(I,J))+KLP(I))*
     $(PMB(I)*SIT(I)*(-1.0)))/(R1(I)*(1.0+2.0*KSH(I)*M(I)*AV(I))*
     $AT(I,J)*C(I,J)*D(I,J)*E(I,J)*100.0))
      IF(W(I,J).GT.10.0) GO TO 20
      W(I,J+1)=W(I,J)+0.1
      J=J+1
      GO TO 10
 20   I=I+1
      IF(I.LE.N) GO TO 5
      DO 30 II=1,100
      X(II)=W(1,II)
      Y(II)=CABS(Z1(1,II)+Z1(2,II)+Z1(3,II))
 30   CONTINUE
      RETURN
      END
C
C
```

APPENDIX D

```
SJOB
C       ************************************************
C       *                                              *
C       *          NETWORK REDUCTION  PROGRAM          *
C       *                                              *
C       ************************************************
        COMPLEX Y(40,40),E(40)
        INTEGER TYPE(40)
        INTEGER GBUS(10)
        COMPLEX YSHUNT,YIJ,ZIJ,YII,YJJ,CURR,S
        COMPLEX CMPLX
        COMPLEX CONJG
C       INITIALIZE VARIABLES
        DO 10 I=1,40
        E(I)=(0.0,0.0)
        TYPE(I)=0
        DO 10 J=1,40
   10   Y(I,J)=(0.0,0.0)
        WRITE(6,2000)
 2000   FORMAT('1',T33,'NETWORK  REDUCTION  PROGRAM')
        READ(5,990) NBUS,NGEN,NFAULT,NPUNCH
  990   FORMAT(4I5)
        WRITE(6,995) NBUS,NGEN,NFAULT,NPUNCH
  995   FORMAT('0'/' NO. OF BUSES',T19,I4 /' NO. OF GENERATORS',T19,I4/
       1' FAULT BUS',T19,I4/' PUNCH FLAG',T19,I4)
        WRITE(6,2005)
 2005   FORMAT('0'/' BUS  DATA'/T37,'LOAD         LOAD      GEN        GEN',
       1'       SHUNT       SHUNT'/T4,'BUS  TYPE     VOLTS      ANGLE        ',
       2'MW       MVAR        MW         MVAR        G           B'/)
C       LOOP HERE FOR EACH BUS.
        N=0
   16   READ(5,1001) I,NTYPE,EMAG,ARG,PL,QL,PG,QG,YSHUNT
 1001   FORMAT(I5,T13,I1,F6.4,F6.2,4F6.2,T62,2F6.3)
        IF(I.EQ.0) GO TO 17
        WRITE(6,1002) I,NTYPE,EMAG,ARG,PL,QL,PG,QG,YSHUNT
 1002   FORMAT(' ',2I5,F10.4,F10.3,4F10.2,2F10.4)
        ARG=ARG*3.14159/180.0
        Y(I,I)=Y(I,I)+YSHUNT+CMPLX(PL,-QL)*.01/EMAG**2
        TYPE(I)=NTYPE
        E(I)=EMAG*CMPLX(COS(ARG),SIN(ARG))
        IF(TYPE(I) .EQ. 0) GO TO 16
        N=N+1
        GBUS(N)=I
        GO TO 16
   17   CONTINUE
        NGEN=N
        WRITE(6,2010)
 2010   FORMAT('0'/' LINE DATA'/'  BUS  BUS  RESISTANCE  REACTANCE',
       1'  SUSCEPTANCE'/)
C       LOOP HERE FOR EACH LINE TO BE READ
   20   READ(5,1003) I,J,ZIJ,B
 1003   FORMAT(2I5,3F10.5)
        IF(I .EQ. 0) GO TO 25
        WRITE(6,1005) I,J,ZIJ,B
 1005   FORMAT(' ',2I5,F10.5,2F12.5)
        YIJ=(1.0,0.0)/ZIJ
        Y(I,I)=Y(I,I)+YIJ+CMPLX(0.0,B/2.0)
        Y(J,J)=Y(J,J)+YIJ+CMPLX(0.0,B/2.0)
        Y(I,J)=Y(I,J)-YIJ
        Y(J,I)=Y(J,I)-YIJ
        GO TO 20
   25   CONTINUE
        WRITE(6,2015)
```

```
2015  FORMAT('0'/' TRANSFORMER  DATA'/'  BUS  BUS  RESISTANCE  ',
     1'REACTANCE    TAP'/)
C     LOOP HERE FOR EACH TRANSFORMER CARD TO BE READ
   30 READ(5,1004)I,J,ZIJ,RATIO
 1004 FORMAT(2I5,3F10.5)
      IF(I.EQ.0) GO TO 35
      WRITE(6,1006) I,J,ZIJ,RATIO
 1006 FORMAT(2I5,F10.4,2X,F10.4,F10.4)
      YIJ=(1.0,0.0)/ZIJ
      YII=YIJ*(1.0/RATIO-1.0)/RATIO
      YJJ=YIJ*(1.0-1.0/RATIO)
      YIJ=YIJ/RATIO
      Y(I,I)=Y(I,I)+YII+YIJ
      Y(J,J)=Y(J,J)+YJJ+YIJ
      Y(I,J)=Y(I,J)-YIJ
      Y(J,I)=Y(J,I)-YIJ
      GO TO 30
   35 CONTINUE
      IF(NFAULT.EQ.0) GO TO 39
C     ZERO ROW AND COLUMN AT THE FAULTED BUS
      DO 38 I=1,NBUS
      Y(I,NFAULT)=(0.0,0.0)
      Y(NFAULT,I)=(0.0,0.0)
   38 CONTINUE
   39 CONTINUE
C     ELIMINATION ON LOAD BUSES.
      DO 60 M=1,NBUS
      IF(M .EQ. NFAULT) GO TO 60
      IF(TYPE(M) .EQ. 1) GO TO 60
      IF(CABS(Y(M,M)) .EQ. 0.0) GO TO 60
      TYPE(M)=-1
      DO 50 I=1,NBUS
C     ONLY PROCESS ROWS AND COLUMNS WHICH HAVE NOT BEEN ELIMINATED.
      IF(TYPE(I) .EQ. -1) GO TO 50
      DO 40 J=1,NBUS
      IF(TYPE(J) .EQ. -1) GO TO 40
      Y(I,J)=Y(I,J)-Y(I,M)*Y(M,J)/Y(M,M)
   40 CONTINUE
   50 CONTINUE
   60 CONTINUE
      WRITE(6,2020)
 2020 FORMAT('0'/'  COMPUTED GENERATION'/'  BUS      MW    MVAR'/)
C     CALCULATED GENERATOR POWERS TO CHECK REDUCTION
      DO 80 I=1,NGEN
      CURR=(0.0,0.0)
      DO 75 J=1,NGEN
   75 CURR=CURR+Y(GBUS(I),GBUS(J))*E(GBUS(J))
      S=E(GBUS(I))*CONJG(CURR)
      WRITE(6,1040) GBUS(I),S
 1040 FORMAT(' ',I5,2P2F10.2)
   80 CONTINUE
      WRITE(6,2025)
 2025 FORMAT('0'/'   EQUIVALENT  GENERATOR  BUS  ADMITANCE MATRIX'/)
      DO 85 I=1,NGEN
   85 WRITE(6,1050) (Y(GBUS(I),GBUS(J)),J=1,NGEN)
 1050 FORMAT((' ',8F10.4))
      IF(NPUNCH.NE.1) GOTO 100
      DO 90 I=1,NGEN
   90 WRITE(6,1060) (Y(GBUS(I),GBUS(J)),J=1,NGEN)
 1060 FORMAT(8F10.4)
  100 CONTINUE
      WRITE(6,2030)
 2030 FORMAT('1')
      STOP
      END

$ENTRY
```

APPENDIX E

```
$JOB
C        ************************************************
C        *                                              *
C        *      LONG-TERM DYNAMIC SIMULATION PROGRAM    *
C        *                                              *
C        ************************************************
C     MAINLINE ROUTINE
      COMPLEX VT,CT,Y,YFICT
      COMPLEX CMPLX,CONJG
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK2/ PBASE(20),H(20),R(20),XL(20),XD(20),XD1(20),
     1XQ(20),XQ1(20),TD1(20),TQ1(20),DAMP(20),C1(20),C2(20)
      COMMON /BLOCK3/ AVRPRM(20,16)
      COMMON /BLOCK4/ TURPRM(20,16)
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK7/ Y(21,21)
      COMMON /BLOCK8/ TYM(200),VAR(200,6),NT,NVAR
      COMMON /BLOCK9/ PRTVAR(20,20)
      COMMON /BLOCKZ/ TRBLPR(20,40)
      COMMON /BLOCKX/F(20),VT0(20),VTT(20),AUX(20),PE0(20),W(20,30),
     SZ(20,20),OM(20)
      EXTERNAL INT
      NHT=0
C     DEFINE HERE VARIOUS CONTROL PARAMETERS
      NT=0
      TIME=0.0
      TFIN=0.0
      NSTEP=0
      NPRINT=0
C     CLEAR INTEGRATOR ARRAYS
      DO 10 I=1,20
      DO 10 J=1,30
      PLUG(I,J)=0.0
      OUT(I,J)=0.0
      SAVE(I,J)=0.0
 10   CONTINUE
      DO 12 I=1,20
      DO 12 J=1,20
 12   PRTVAR(I,J)=0.0
      WRITE(6,990)
 990  FORMAT('1',T39,'POWER SYSTEM RESERACH GROUP'//
     1T35,'UNIVERSITY OF PETROLEUM AND MINERALS'//
     2T35,'LONG TERM DYNAMIC SIMULATION PROGRAM'//)
      READ(5,1000) NGEN,TSTEP,TPRINT
 1000 FORMAT(I5,5X,2F10.4)
      WRITE(6,1005) NGEN,TSTEP,TPRINT
 1005 FORMAT('0NO.OF GENERATORS',T20,I5/' TIME STEP',T20,F6.3/
     1'TPRINT INTERVAL',T20,F6.3)
      WRITE(6,1008)
 1008 FORMAT('0GENERATOR PARAMETERS')
C     READ GENERATOR PARAMETERS.
      DO 20 I=1,NGEN
      READ(5,1010)            PBASE(I),H(I),R(I),XL(I),XD(I),
     1XD1(I),XQ(I),XQ1(I),TD1(I),TQ1(I),DAMP(I),C1(I),C2(I)
 1010 FORMAT(7F10.4)
      WRITE(6,1015) I,        PBASE(I),H(I),R(I),XL(I),XD(I),
     1XD1(I),XQ(I),XQ1(I),TD1(I),TQ1(I),DAMP(I),C1(I),C2(I)
 1015 FORMAT(1X,I5,8G12.4/6X,8G12.4)
C     CONVERT DATA TO 100 MW BASE.
      C=100.0/PBASE(I)
      H(I)=H(I)/C
      R(I)=R(I)*C
```

```
      XL(I)=XL(I)*C
      XD(I)=XD(I)*C
      XD1(I)=XD1(I)*C
      XQ(I)=XQ(I)*C
      XQ1(I)=XQ1(I)*C
      DAMP(I)=DAMP(I)/C
20    CONTINUE
      WRITE(6,1018)
1018  FORMAT('0 EXCITATION SYSTEM PARAMETERS')
C     READ EXCITATION SYSTEM PARAMETERS.
      DO 30 I=1,NGEN
      READ(5,1020)  (AVRPRM(I,J),J=1,16)
1020  FORMAT(7F10.4)
      WRITE(6,1025) I,(AVRPRM(I,J),J=1,16)
1025  FORMAT(1X,I5,8G12.4/6X,8G12.4)
30    CONTINUE
      IF(NHT.EQ.0)GO TO 999
      WRITE(6,1028)
1028  FORMAT('0 TURBINE-GOVERNOR PARAMETERS')
C     READ TURBINE AND GOVERNOR PARAMETERS.
      DO 40 I=1,NHT
      READ(5,1030) (TURPRM(I,J),J=1,16)
1030  FORMAT(7F10.4)
      WRITE(6,1035)  I,(TURPRM(I,J),J=1,16)
1035  FORMAT(1X,I5,8G12.4/6X,8G12.4)
40    CONTINUE
      GO TO 110
C     READ TURBINE BOILER PARAMETERS HERE
999   DO 111 I=1,NGEN
      READ(5,*)(TRBLPR(I,J),J=1,40)
111   CONTINUE
      WRITE(6,5028)
5028  FORMAT('0 STEAM TURBINE-GOVERNOR & BOILER PARAMETERS')
      DO 116 I=1,NGEN
      WRITE(6,2000)(TRBLPR(I,J),J=1,40)
2000  FORMAT(10F10.4/)
116   CONTINUE
110   WRITE(6,1038)
1038  FORMAT('0 INITIAL GENERATOR TERMINAL CONDITIONS'/
     1T8,'    ',T15,'MW',T26,'MVAR',T36,'VOLTS',T46,'ANGLE')
C     READ CONDITIONS ON TERMINAL BUSES.
      DO 50 I=1,NGEN
      READ(5,1040)     PT,QT,VMAG,VARG
1040  FORMAT(        2P2F10.4,0P2F10.4)
      WRITE(6,1045) I,PT,QT,VMAG,VARG
1045  FORMAT(1X,I5,5X,2P2F10.3,0P2F10.5)
      VARG=VARG*3.1416/180.0
      VT(I)=VMAG*CMPLX(COS(VARG),SIN(VARG))
      CT(I)=CONJG(CMPLX(PT,QT)/VT(I))
50    CONTINUE
C     CALL EQUIPMENTS SUBROUTINES TO CALCULATE INITIAL CONDITIONS.
C     CALL STATEMENTS MUST BE GENERATED BY USER.
      CALL GEN1IC(1)
      CALL GEN1IC(2)
      CALL GEN1IC(3)
      CALL AVR1IC(1)
      CALL AVR1IC(2)
      CALL AVR1IC(3)
      CALL TRBLIC(1)
      CALL TRBLIC(2)
      CALL TRBLIC(3)
C     LOOP HERE FOR EACH NEW NETWORK CONDITION.
70    CONTINUE
```

```
        TOLD = TFIN
C       READ THE CONTROL CARD.
        READ(5,1050) TFIN
 1050   FORMAT(F10.4)
        IF(TFIN.EQ.0.0) GO TO 150
        WRITE(6,1055)  TOLD,TFIN
 1055   FORMAT('0',T9,'TERMINAL ADMITTANCE MATRIX FROM',F8.3,' TO',F8.3,
       1' SECS.')
C       READ THE NEW ADMITTANCE MATRIX.
        DO 72 I=1,NGEN
        READ(5,1060) (Y(I,J),J=1,NGEN)
 1060   FORMAT(7F10.4)
        WRITE(6,1065) (Y(I,J),J=1,NGEN)
 1065   FORMAT((T9 ,8F10.4))
 72     CONTINUE
        CALL MATRIX (NGEN)
        WRITE(6,1076)
 1076   FORMAT('0')
C       LOOP HERE FOR EACH INTGRATION STEP
 100    CONTINUE
C       SOLVE THE NETWORK.
        CALL NWSOL(NGEN)
C       CALL EQUIPMENT SUBROUTINES TO CALCULATE STATE VARIABLE DERIVATIVES
C       CALL STATEMENT MUST BE GENERATED BY USER.
        CALL AVR1(1)
        CALL AVR1(2)
        CALL AVR1(3)
        CALL TRBL(1)
        CALL TRBL(2)
        CALL TRBL(3)
        CALL GEN1(1)
        CALL GEN1(2)
        CALL GEN1(3)
C       CHECK FOR OUTPUT
        IF(NSTEP.EQ.0) CALL OUTPUT(NGEN)
        IF(NPRINT*TSTEP .LT. TPRINT-.0001) GO TO 125
        CALL OUTPUT(NGEN)
        NPRINT=0
 125    CONTINUE
C       PERFORM INTEGRATION STEP.
        CALL INT(NGEN)
        NSTEP=NSTEP+1
        TIME=NSTEP*TSTEP
        NPRINT=NPRINT+1
C       CHECK FOR NEW NETWORK CONDITION.
        IF (TIME.LT.TFIN) GO TO 100
C       LOOP BACK FOR NEW NETWORK CONDITION.
        GO TO 70
C       COME HERE WHEN RUN IS COMPLETED.
 150    CONTINUE
C       CALL PLOT
        STOP
        END

        SUBROUTINE MATRIX(NGEN)
C       SUBROUTINE TO CALCULATE EQUIVALENT Y MATRIX FOR INTERNAL
C       GENERATOR BUSES.
        COMMON /BLOCK2/ PBASE(20),H(20),R(20),XL(20),XD(20),XD1(20),
       1XQ(20),XQ1(20),TD1(20),TQ1(20),DAMP(20),C1(20),C2(20)
        COMMON /BLOCK7/ Y(21,21)
        COMPLEX Y,YFICT,CMPLX,CONJG
C       AUGMENT Y MATRIX WITH GENERATOR BUSES AND ELIMINATE THE
C       TERMINAL BUSES.
```

```
      N1=NGEN+1
      DO 80 I=1,NGEN
C     MOVE TERMINAL BUS OUTSID OF MATRIX.
      Y(N1,N1)=Y(I,I)
      Y(I,I)=(0.0,0.0)
      DO 75 J=1,NGEN
C     MOVE ROW
      Y(N1,J)=Y(I,J)
      Y(I,J)=(0.0,0.0)
C     MOVE COLUMN
      Y(J,N1)=Y(J,I)
      Y(J,I)=(0.0,0.0)
   75 CONTINUE
C     ADD IN GENERATOR BUS
      YFICT=CMPLX(R(I),-(XD1(I)+XQ1(I))/2.0)/(R(I)*R(I)+XD1(I)*XQ1(I))
      Y(I,I)=YFICT
C     CHECK IF TERMINAL BUS IS GROUNDED.
      IF(CABS(Y(N1,N1)) .EQ. 0.0) GO TO 80
      Y(N1,N1)=Y(N1,N1)+YFICT
      Y(I,N1)=-YFICT
      Y(N1,I)=-YFICT
C     ELIMINATE THE TERMINAL BUS.
      DO 76 M=1,NGEN
      DO 76 N=M,NGEN
      Y(M,N)=Y(M,N)-Y(M,N1)*Y(N1,N)/Y(N1,N1)
      Y(N,M)=Y(M,N)
   76 CONTINUE
   80 CONTINUE
      RETURN
      END

      SUBROUTINE NWSOL(NGEN)
C     SUBROUTINE TO SOLVE NETWORK AND ARMATURE EQUATIONS..
      COMPLEX SCALE,ROTATE
      REAL ID,IQ
      COMPLEX CMPLX,CONJG,Y,VT,CT
      COMPLEX VOLD,YFICT
      COMMON /BLOCK2/ PBASE(20),H(20),R(20),XL(20),XD(20),XD1(20),
     1XQ(20),XQ1(20),TD1(20),TQ1(20),DAMP(20),C1(20),C2(20)
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK7/ Y(21,21)
      COMPLEX EFICT(20),E(20)
      REAL DEL(20)
      DO 10 I=1,NGEN
      DEL(I)=OUT(I,2)
      EQ=OUT(I,3)
      ED=OUT(I,4)
C     TRANSFORM VOLTAGE TO SYNCHRONOUS REFERENCE.
      THETA=DEL(I)-3.1416/2.0
      E(I)=CMPLX(ED,EQ)*CMPLX(COS(THETA),SIN(THETA))
   10 CONTINUE
      ITER=0
C     LOOP HERE FOR EACH ITERATION
   15 CONTINUE
      ITER=ITER+1
      DO 20 I=1,NGEN
      THETA=DEL(I)-3.1416/2.0
      SCALE=CMPLX(0.0,(XQ1(I)-XD1(I))*0.5)/CMPLX(R(I),-(XQ1(I)+XD1(I))*
     10.5)
      ROTATE=CMPLX(COS(2.0*THETA),SIN(2.0*THETA))
      EFICT(I)=E(I)+SCALE*CONJG(E(I)-VT(I))*ROTATE
   20 CONTINUE
```

```
      DO 30 I=1,NGEN
      CT(I)=(0.0,0.0)
      DO 25 J=1,NGEN
 25   CT(I)=CT(I)+Y(I,J)*EFICT(J)
 30   CONTINUE
      DO 40 I=1,NGEN
      YFICT=CMPLX(R(I),-(XD1(I)+XQ1(I))/2.0)/(R(I)*R(I)+XD1(I)*XQ1(I))
      VT(I)=EFICT(I)-CT(I)/YFICT
 40   CONTINUE
C     CHECK FOR CONVERGENCE
      NFLAG=0
      DO 50 I=1,NGEN
      EQ=OUT(I,3)
      ED=OUT(I,4)
C     TRANSFORM TERMINAL VOLTAGE AND CURRENT TO MACHINE REFERENCE
      THETA=DEL(I)-3.1416/2.0
      ROTATE=CMPLX(COS(THETA),-SIN(THETA))
      ID=REAL(CT(I)*ROTATE)
      IQ=AIMAG(CT(I)*ROTATE)
      VD=REAL(VT(I)*ROTATE)
      VQ=AIMAG(VT(I)*ROTATE)
      IF(ABS(EQ-R(I)*IQ-XD1(I)*ID-VQ) .GT. .001) NFLAG=1
      IF(ABS(ED-R(I)*ID+XQ1(I)*IQ-VD) .GT. .001) NFLAG=1
      VD1=ED-R(I)*ID+XQ1(I)*IQ
      VQ1=EQ-R(I)*IQ-XD1(I)*ID
 50   CONTINUE
      IF(ITER .GE. 10) GO TO 60
      IF(NFLAG .EQ. 1) GO TO 15
      RETURN
 60   WRITE(6,1025)
 1025 FORMAT('0 SALIENCY ITERATION NOT CONVERTED')
      DO 70 I=1,NGEN
      WRITE(6,1010) I,VT(I),CT(I),VD,VQ,VD1,VQ1,ID,IQ
 1010 FORMAT(' TERN',I5,10F10.4)
 70   CONTINUE
      STOP
      END

      SUBROUTINE GEN1(I)
C     MODEL OF SYNCHRONOUS GENERATOR WITH FIELD WINDING IN D-AXIS AND
C     DAMPER WINDING IN Q-AXIS.
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK2/ PBASE(20),H(20),R(20),XL(20),XD(20),XD1(20),
     1XQ(20),XQ1(20),TD1(20),TQ1(20),DAMP(20),C1(20),C2(20)
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK9/ PRTVAR(20,20)
      REAL CSAT(20)
      COMPLEX CONJG,CMPLX,VT,CT,EQD,CURR
      REAL ID,IQ
C     ENTER HERE FOR EACH INTEGRATION STEP.
C     DEFINE INTEGRATOR OUTPUTS.
      OME=OUT(I,1)
      DEL=OUT(I,2)
      EQ =OUT(I,3)
      ED =OUT(I,4)
C     TRANSFORM CURRENT TO MACHINE REFRENCE.
      CURR=CT(I)*CMPLX(SIN(DEL),COS(DEL))
      ID=REAL(CURR)
      IQ=AIMAG(CURR)
C     CALCULATE GENERATOR OUTPUT PLUS LOSSES.
      PE=REAL(VT(I)*CONJG(CT(I)))
      QE=AIMAG(VT(I)*CONJG(CT(I)))
```

```
      PL=CABS(CURR)**2*R(I)
C     ADJUST REACTANCE AND TIME CONSTANCE TO ACCOUNT FOR SATURATION.
      XDS=CSAT(I)*XD(I)+(1.0-CSAT(I))*XL(I)
      XQS=CSAT(I)*XQ(I)+(1.0-CSAT(I))*XL(I)
      IF(XQ1(I) .EQ. XQ(I)) XQS=XQ(I)
      TD1S=TD1(I)*(1.0-(1.0-CSAT(I))*(XD(I)-XD1(I))/(XD(I)-XL(I)))
      TQ1S=TQ1(I)*(1.0-(1.0-CSAT(I))*(XQ(I)-XQ1(I))/(XQ(I)-XL(I)))
      EAQ=EQ-(XD1(I)-XL(I))*ID
      EAD=ED+(XQ1(I)-XL(I))*IQ
      IF(XQ1(I) .EQ. XQ(I)) EAD=0.0
      EAT=SQRT(EAQ**2+EAD**2)
      CSAT(I)=1.0/(1.0+C1(I)*EXP(C2(I)*EAT))
C     DEFINE INTEGRATOR INPUTS.
C     SET UP PRINTOUT VARIABLE.
      PLUG(I,1)=(PM(I)-PE-PL-DAMP(I)*OME)/(2.0*H(I))
      PLUG(I,2)=377.0*OME
      PLUG(I,3)=(CSAT(I)*EF(I)-EQ-(XDS-XD1(I))*ID)/TD1S
      PLUG(I,4)=(-ED+(XQS-XQ1(I))*IQ)/TQ1S
      PRTVAR(I,1)=DEL*180.0/3.142
      PRTVAR(I,2)=OME
      PRTVAR(I,3)=EQ
      PRTVAR(I,4)=ED
      PRTVAR(I,5)=CABS(VT(I))
      PRTVAR(I,6)=PE*100.0/PBASE(I)
      PRTVAR(I,7)=QE*100.0/PBASE(I)
      PRTVAR(I,8)=EF(I)
      PRTVAR(I,9)=PM(I)*100.0/PBASE(I)
      PRTVAR(I,10)=CSAT(I)
      PRTVAR(I,11)=EAT
      RETURN
C     ENTER HERE TO CALCULATE INITIAL CONDITIONS.
      ENTRY GEN1IC(I)
      CSAT(I)=1.0
      DO 100 J=1,3
      XDS=CSAT(I)*XD(I)+(1.0-CSAT(I))*XL(I)
      XQS=CSAT(I)*XQ(I)+(1.0-CSAT(I))*XL(I)
      IF(XQ1(I) .EQ. XQ(I))XQS=XQ(I)
C     CALCULATE ANGLE OF GENERATOR Q AXIS
      EQD=VT(I)+CMPLX(R(I),XQS   )*CT(I)
      DEL=ATAN2(AIMAG(EQD),REAL(EQD))
C     TRANSFORM CURRENT ONTO GENERATOR REFERENCE.
      CURR=CT(I)*CMPLX(SIN(DEL),COS(DEL))
      ID=REAL(CURR)
      IQ=AIMAG(CURR)
      EQ=CABS(EQD)-(XQS    -XD1(I))*ID
      EF(I)=(EQ+(XDS-XD1(I))*ID)/CSAT(I)
      ED=(XQS   -XQ1(I))*IQ
      EAQ=EQ-(XD1(I)-XL(I))*ID
      EAD=ED+(XQ1(I)-XL(I))*IQ
      IF(XQ1(I) .EQ. XQ(I))EAD=0.0
      EAT=SQRT(EAQ**2+EAD**2)
      CSAT(I)=1.0/(1.0+C1(I)*EXP(C2(I)*EAT))
  100 CONTINUE
      PE=REAL(VT(I)*CONJG(CT(I)))+CABS(CURR)**2*R(I)
      PM(I)=PE
      OUT(I,1)=0.0
      OUT(I,2)=DEL
      OUT(I,3)=EQ
      OUT(I,4)=ED
      RETURN
      END
C     ROTATING EXCITATION SYSTEM -IEEE TYPE 1 MODEL.
```

```
      SUBROUTINE AVR1(I)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON/BLOCK3/          KA(20),KE(20),KF(20),TA(20),TE(20),
     1TF(20),VRMIN(20),VRMAX(20),C1(20),C2(20),DUM(20,6)
      COMMON/BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON/BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON/BLOCK9/ PRTVAR(20,20)
      COMPLEX VT,CT
      REAL KA,KE,KF,VREF(20),SE(20)
C     ENTER HERE FOR EACH INTEGRATION STEP.
C     DEFINE INTEGRATOR OUTPUTS.
      X5=OUT(I,6)
      EF(I)=OUT(I,5)
      X3=OUT(I,7)
C     CALCULATE INTERMEDIATE VARIABLES.
      X1=VREF(I)-CABS(VT(I))
      X2=KF(I)/TF(I)*EF(I)-X3
      X4=X1-X2
      X6=X5
      IF(X6 .LT. VRMIN(I)) X6=VRMIN(I)
      IF(X6 .GT. VRMAX(I)) X6=VRMAX(I)
      X7=SE(I)*EF(I)
      X8=X6-X7
C     DEFINE INTEGRATOR INPUTS.
      PLUG(I,5)=X8/TE(I)-KE(I)/TE(I)*EF(I)
      PLUG(I,6)=KA(I)/TA(I)*X4-X5/TA(I)
      PLUG(I,7)=X2/TF(I)
      RETURN
C     ENTER HERE TO CALCULATE INITIAL CONDITIONS.
      ENTRY AVR1IC(I)
      SE(I)=C1(I)*EXP(C2(I)*EF(I))
      VREF(I)=CABS(VT(I))+(KE(I)+SE(I))*EF(I)/KA(I)
      OUT(I,5)=EF(I)
      OUT(I,6)=EF(I)*(KE(I)+SE(I))
      OUT(I,7)=EF(I)*KF(I)/TF(I)
      IF(OUT(I,6) .LT. VRMIN(I)) WRITE(6,1020)  I
      IF(OUT(I,6) .GT. VRMAX(I)) WRITE(6,1020)  I
 1020 FORMAT('0**** AVR VOLTAGE LIMIT IS EXCEEDED BY INITIAL ON',
     1' UNIT',I3/)
      RETURN
      END
C     STATIC EXCITATION SYSTEM - IEEE TYPE 1S MODEL.

      SUBROUTINE AVR2(I)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK3/ KA(20),KF(20),TA(20),TF(20),KP(20),DUM(20,11)
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK9/ PRTVAR(20,20)
      COMPLEX VT,CT
      REAL KA,KF,KP,VREF(20)
C     INTER HERE FOR EACH INTEGRATION STEP.
C     DEFINE INTEGRATOR OUTPUTS.
      X5=OUT(I,5)
      X3=OUT(I,6)
C     CALCULATE INTERMEDIATE VARIABLES.
      EF(I)=X5
      VMAG=CABS(VT(I))
      IF(X5 .GT. KP(I)*VMAG) EF(I)=KP(I)*VMAG
      IF(X5 .LT. -KP(I)*VMAG) EF(I)=-KP(I)*VMAG
      X2=EF(I)*KF(I)/TF(I)-X3
      X1=VREF(I)-VMAG
      X4=X1-X2
```

```
C      CALCULATE INTEGRATOR INPUTS.
       PLUG(I,5)=X4*KA(I)/TA(I)-X5/TA(I)
       PLUG(I,6)=X2/TF(I)
       RETURN
C      ENTER HERE TO CALCULATE INITIAL CONDITIONS.
       ENTRY AVR2IC(I)
       OUT(I,5)=EF(I)
       OUT(I,6)=EF(I)*KF(I)/TF(I)
       VREF(I)=CABS(VT(I))+EF(I)/KA(I)
C      CHECK IF INITIAL CONDITIONS ARE WITH LIMITS.
       VMAG=CABS(VT(I))
       IF(EF(I) .GT. KP(I)*VMAG) WRITE(6,1020) I
       IF(EF(I) .GT. -KP(I)*VMAG) WRITE(6,1020)I
 1020  FORMAT('0**** AVR VOLTAGE LIMIT IS EXCEEDED BY INITIAL FIELD ON',
      1' UNIT',I3/)
       RETURN
       END
C      MODEL OF ROTATING EXCITER WITH AUXILIARY STABILIZER.

       SUBROUTINE AVR3(I)
       COMMON /BLOCK1/ TIME,TSTEP
       COMMON /BLOCK2/ PBASE(20),H(20),R(20),XL(20),XD(20),XD1(20),
      1XQ(20),XQ1(20),TD1(20),TQ1(20),DAMP(20),C1(20),C2(20)
       COMMON/ BLOCK3/ KA(20),TA1(20),TA2(20),KB(20),KE(20),TE(20),
      1KD(20),TD(20),KC(20),TC(20),T1(20),T3(20),KT(20),TFD(20),T(20),
      2UMAX(20)
       REAL KA,KB,KE,KD,KC,KT,VREF(20)
       COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
       COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
       COMMON /BLOCK9/ PRTVAR(20,20)
       COMPLEX CMPLX,CONJG
       COMPLEX VT,CT,EQD
C      ENTER HERE FOR EACH INTEGRATION STEP.
C      DEFINE STABLIZER VARIABLES.
       OME=OUT(I,1)
       X7=OME
       X8=OUT(I,13)
       X9=OUT(I,14)+T1(I)/T3(I)*X8
       X10=OUT(I,15)+T1(I)/T3(I)*X9
       U=X10-OUT(I,16)
       IF(U .GT. UMAX(I)) U=UMAX(I)
       IF(U .LT. -UMAX(I)) U=-UMAX(I)
C      DEFINE STABLIZER INTEGRATOR INPUTS.
       PLUG(I,13)=(KT(I)*X7-X8)/TFD(I)
       PLUG(I,14)=(X8-X9)/T3(I)
       PLUG(I,15)=(X9-X10)/T3(I)
       PLUG(I,16)=U/T(I)
C      DEFINE AVR VARIABLES.
       EF(I)=OUT(I,5)
       X5=CABS(VT(I))*KC(I)/TC(I)-OUT(I,8)
       X6=CABS(VT(I))+X5
       X4=EF(I)*KB(I)*KD(I)/TD(I)-OUT(I,7)
       X1=VREF(I)+U-X4-X6
       X2=X1*KA(I)*TA1(I)/TA2(I)+OUT(I,6)
C      DEFINE AVR INTEGRATOR INPUTS.
       PLUG(I,5)=X2*KE(I)/KB(I)/TE(I)-EF(I)/TE(I)
       PLUG(I,6)=X1*KA(I)/TA2(I)-X2/TA2(I)
       PLUG(I,7)=X4/TD(I)
       PLUG(I,8)=X5/TC(I)
       PRTVAR(I,12)=U
       RETURN
C      ENTER HERE TO CALCULATE INITIAL CONDITIONS.
       ENTRY AVR3IC(I)
```

```
C      SET INITIAL CONDITIONS FOR STABLIZER INTEGRATORS.
       OUT(I,13)=0.0
       OUT(I,14)=0.0
       OUT(I,15)=0.0
       OUT(I,16)=0.0
C      SET INITIAL CONDITIONS FOR AVR
       VREF(I)=EF(I)*KB(I)/KA(I)/KE(I)+CABS(VT(I))
       OUT(I,5)=EF(I)
       OUT(I,6)=EF(I)*KB(I)/KE(I)*(1.0-TA1(I)/TA2(I))
       OUT(I,7)=EF(I)*KB(I)*KD(I)/TD(I)
       OUT(I,8)=CABS(VT(I))*KC(I)/TC(I)
       RETURN
       END
C      STEAM TURBINE AND GOVERNOR MODEL.

       SUBROUTINE TUR1(I)
       COMMON /BLOCK1/ TIME,TSTEP
       COMMON /BLOCK4/ PBASE(20),THP(20),TIP(20),TLP(20),FHP(20),FIP(20),
      1FLP(20),R(20),TS(20),DGMIN(20),DGMAX(20),GMIN(20),GMAX(20),
      1DUM(20,3)
       COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
       COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
       COMMON /BLOCK9/ PRTVAR(20,20)
       COMPLEX VT,CT
       REAL WREF(10)
C      ENTER HERE FOR EACH TIME STEP.
C      DEFINE INTEGRATOR OUTPUTS.
       OME=OUT(I,1)
       X4=OUT(I,9)
       X5=OUT(I,10)
       X6=OUT(I,11)
       X7=OUT(I,12)
C      CALCULATE INTERMEDIATE VARIABLES.
       G=X4
       X1=(WREF(I)-OME)/R(I)
       X2=(X1-G)/TS(I)
       X3=X2
       IF(X2 .GT. DGMAX(I)) X3=DGMAX(I)
       IF(X2 .LT. DGMIN(I)) X3=DGMIN(I)
       PM(I)=(FHP(I)*X5+FIP(I)*X6+FLP(I)*X7)*PBASE(I)/100.0
C      CALCULATE INTEGRAL INPUTS.
       PLUG(I,9)=X3
       PLUG(I,10)=(G-X5)/THP(I)
       PLUG(I,11)=(X5-X6)/TIP(I)
       PLUG(I,12)=(X6-X7)/TLP(I)
       PRTVAR(I,12)=G
       RETURN
C      ENTER HERE TO CALCULATE INITIAL CONDITIONS.
       ENTRY TUR1IC(I)
       OME=OUT(I,1)
       G=PM(I)*100.0/PBASE(I)/(FHP(I)+FIP(I)+FLP(I))
       OUT(I,9)=G
       OUT(I,10)=G
       OUT(I,11)=G
       OUT(I,12)=G
C      CALCULATE SET POINT.
       WREF(I)=OME+OUT(I,9)*R(I)
C      CHECK IF INITIAL CONDITIONS ARE WITHEN LIMITS.
       IF(OUT(I,9) .GT. GMAX(I)) WRITE(6,1020) I
       IF(OUT(I,9) .LT. GMIN(I)) WRITE(6,1020) I
 1020  FORMAT('0 TURBINE GATE LIMIT IS EXCEEDED BY INITIAL POWER',
      1' ON UNIT',I3/)
       RETURN
```

```
      END
C
C     HYDRAULIC TURBINE AND GOVERNOR MODEL.

      SUBROUTINE TUR2(I)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK4/ PBASE(20),TW(20),TS(20),TR(20),PDR(20),TDR(20),
     1DGMIN(20),DGMAX(20),GMIN(20),GMAX(20),DUM(20,6)
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK9/ PRTVAR(20,20)
      COMPLEX VT,CT
      REAL WREF(20)
C     ENTER HERE FOR EACH TIME STEP.
C     DEFINE INTEGRATOR OUTPUTS.
      OME=OUT(I,1)
      X4=OUT(I,9)
      X5=OUT(I,10)
      X7=OUT(I,11)
C     CALCULATE INTERMEDIATE VARIABLES.
      G=X4
      IF(G .GT. GMAX(I)) G=GMAX(I)
      IF(G .LT. GMIN(I)) G=GMIN(I)
      X6=G*TDR(I)-X5
      X1=WREF(I)-OME
      X2=(X1-X6-G*PDR(I))/TS(I)
      X3=X2
      IF(X2 .GT. DGMAX(I)) X3=DGMAX(I)
      IF(G  .LT. DGMIN(I)) X3=DGMIN(I)
      X8=2.0*(X7-G)
      PM(I)=X8*PBASE(I)/100.0
C     CALCULATE INTEGRATOR INPUTS
      PLUG(I,9)=X3
      PLUG(I,10)=X6/TR(I)
      PLUG(I,11)=(G-X8)/TW(I)
      PRTVAR(I,12)=G
      RETURN
C     ENTER HERE TO CALCULATE INITIAL CONDITIONS.
      ENTRY TUR2IC(I)
      OME=OUT(I,1)
      OUT(I,9)=PM(I)*100.0/PBASE(I)
      OUT(I,10)=PM(I)*100.0/PBASE(I)*TDR(I)
      OUT(I,11)=1.5*PM(I)*100.0/PBASE(I)
C     CALCULATE SET POINT.
      WREF(I)=OME+OUT(I,9)*PDR(I)
C     CHECK IF INITIAL CONDITIONS ARE WITHEN LIMITS.
      IF(OUT(I,9) .GT. GMAX(I)) WRITE(6,1020) I
      IF(OUT(I,9) .LT. GMIN(I)) WRITE(6,1020) I
 1020 FORMAT('0**** TURBINE GATE LIMIT IS EXCEEDED BY INITIAL POWER',
     1' ON UNIT',I3/)
      RETURN
      END
C     SUBROUTINE TO CALCULATE STATE VARIABLES FOR NEXT INCREMENT IN TIME

      SUBROUTINE INT(NGEN)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      IF(TIME .GT. 0.0) GO TO 20
      DO 10 I=1,NGEN
      DO 10 J=1,30
   10 SAVE(I,J)=PLUG(I,J)
      NFLAG=1
   20 CONTINUE
```

```
      DO 30 I=1,NGEN
      DO 30 J=1,30
      OUT(I,J)=OUT(I,J)+PLUG(I,J)*TSTEP+(PLUG(I,J)-SAVE(I,J))*0.5*TSTEP
30    SAVE(I,J)=PLUG(I,J)
      RETURN
      END
C
C     SUBROUTINE TO PRINTOUT SYSTEM VARIABLES.

      SUBROUTINE OUTPUT(NGEN)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK8/ TYM(200),VAR(200,6),NT,NVAR
      COMMON /BLOCK9/ PRTVAR(20,20)
      IF(TIME .EQ. 0.0) WRITE(6,2000)
2000  FORMAT('1'//T42,'SIMULATED RESPONSES',//T4,'TIME  GEN  ROTOR   ',
     1'ROTOR    EQ''      ED''     TERM     ELEC-POWER     BOILER   ',
     2'MECH    THROT  STEAM  '/T4,'SECS   NO  ANGLE    SPEED    ',
     3'VOLTS    VOLTS  VOLTS     REAL    IMAG    DEMAND    POWER  ',
     4'PRESS.   FLOWS'/)
      WRITE(6,1010) TIME
1010  FORMAT(' ',F7.3)
      DO 10 I=1,NGEN
      WRITE(6,1000) I,(PRTVAR(I,J),J=1,7),PRTVAR(I,16),PRTVAR(I,9),
     $PRTVAR(I,14),PRTVAR(I,15)
1000  FORMAT(' ',8X,I2,F11.3,12F8.4)
C     WRITE(12,1001) PRTVAR(I,1),PRTVAR(I,2),PRTVAR(I,6),PRTVAR(I,9),
C    $PRTVAR(I,14),PRTVAR(I,15),PRTVAR(I,16)
C 1001  FORMAT(5X,F11.3,6F10.4)
10    CONTINUE
C     SET UP THE VARIABLES TO BE PLOTTED.
C     NT=NT+1
C     TYM(NT)=TIME
C     VAR(NT,1)=PRTVAR(1,1)
C     VAR(NT,2)=PRTVAR(2,1)
C     VAR(NT,3)=PRTVAR(3,1)
C     VAR(NT,4)=PRTVAR(1,14)
C     VAR(NT,5)=PRTVAR(2,14)
C     VAR(NT,6)=PRTVAR(3,14)
      RETURN
      END
C     SUBROUTINE TO PLOT GRAPHS OF SYSTEM VARIABLES.

      SUBROUTINE PLOT
      COMMON /BLOCK8/ TYM(200),VAR(200,6),NT,NVAR
      LOGICAL SYMBOL(6),PLUS,NAME(6,40),ALINE(132),BLANK
      DATA SYMBOL/'A','B','C','D','E','F'/
      DATA PLUS/'+'/,BLANK/' '/
      REAL VMAX(6),VMIN(6)
      REAL YVAL(11)
C     READ GRAPH NAMES AND MINIMUM AND MAXIMUM VALUES.
      DO 3 I=1,7
      IF(I .EQ. 7) GO TO 5
3     READ(5,1000,END=5) (NAME(I,J),J=1,40),VMIN(I),VMAX(I)
1000  FORMAT(40A1,F10.5,F10.5)
5     NVAR=I-1
      IF(NVAR .EQ. 0) RETURN
      WRITE(6,1060)
1060  FORMAT('1')
C     WRITE HEADINGS FOR EACH GRAPH.
      DO 20 I=1,NVAR
      RANGE=VMAX(I)-VMIN(I)
      LOG=ALOG10(RANGE)
      SCALE=1.0*10.0**LOG
```

```
      DO 10 J=1,11
10    YVAL(J)=(VMIN(I)+(J-1)*RANGE/10.0)/SCALE
      WRITE(6,1010) SYMBOL(I),(NAME(I,J),J=1,40),SCALE
1010  FORMAT('0',T12,A1,' - ',40A1,T93,'SCALE FACTOR = ',1PE7.1)
      WRITE(6,1020) (YVAL(J),J=1,11)
1020  FORMAT(' ',T10,11(F5.2,5X))
20    CONTINUE
C     WRITE Y AXIS
      WRITE(6,1030) (PLUS,LOC=1,101)
1030  FORMAT('0    TIME   ',101A1)
C     PLOT GRAPHS
      DO 50 J=1,NT
      DO 28 LOC=1,101
28    ALINE(LOC)=BLANK
      ALINE(1)=PLUS
      IF(MOD( J,10) .NE. 1) GO TO 32
C     INCLUDE GRID POINTS
      DO 30 LOC=1,101,10
30    ALINE(LOC)=PLUS
32    CONTINUE
C     INCLUDE GRAPH POINTS.
      DO 35 I=1,NVAR
      LOC=(VAR(J,I)-VMIN(I))/(VMAX(I)-VMIN(I))*100.0+1.0
      IF(LOC .LT. 1) LOC=1
      IF(LOC .GT. 101) LOC=101
      ALINE(LOC)=SYMBOL(I)
35    CONTINUE
      IF(MOD(J,10) .EQ. 1) WRITE(6,1040) TYM(J),(ALINE(LOC),LOC=1,101)
1040  FORMAT(T4,F7.3,1X,101A1)
      IF(MOD( J,10) .NE. 1) WRITE(6,1045) TYM(J),(ALINE(LOC),LOC=1,101)
1045  FORMAT(T12,101A1)
50    CONTINUE
60    CONTINUE
      WRITE(6,1060)
      RETURN
      END
C
C     STEAM TURBINE GOVERNOR AND BOILER MODEL
C

      SUBROUTINE TRBL(I)
      COMMON /BLOCK1/ TIME,TSTEP
      COMMON /BLOCK5/ VT(20),CT(20),EF(20),PM(20)
      COMMON /BLOCK6/ PLUG(20,30),OUT(20,30),SAVE(20,30)
      COMMON /BLOCK9/ PRTVAR(20,20)
      COMMON /BLOCKZ/XTRM(20),XC1(20),XRLRM(20),XRLRMI(20),XPLRM(20),
     SXPLRMI(20),XR1(20),XK1(20),XK2(20),XK3(20),XK4(20),XLLM(20),
     SXLLMI(20),XIPL(20),XIPLG(20),XTG(20),XRGM(20),XRGMI(20),XPGM(20),
     SXPGMI(20),XTHP(20),XTIP(20),XTLP(20),XFHP(20),XFIP(20),XFLP(20),
     SXTHS(20),XKP(20),XKI(20),XTR(20),XGLM(20),XGLMI(20),XDE(20),
     SXTF(20),XKAUX(20),XVMIN(20),XFMIN(20),XCD(20),XKSH(20),XPBASE(20)
      COMMON /BLOCKX/F(20),VT0(20),VTT(20),AUX(20),PE0(20),W(20,30),
     SZ(20,20),OM(20)
      COMPLEX VT,CT
C
C     ENTER HERE FOR EACH TIME STEP
C     DEFINE INTEGRATER OUTPUT
C
      OM(I)=OUT(I,1)
      Z(I,1)=OUT(I,21)
      Z(I,2)=OUT(I,22)
      Z(I,3)=OUT(I,23)
      Z(I,4)=OUT(I,24)
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```
      Z(I,5)=OUT(I,25)
      Z(I,6)=OUT(I,26)
      Z(I,7)=OUT(I,27)
      Z(I,8)=OUT(I,28)
      Z(I,9)=OUT(I,29)
      Z(I,10)=OUT(I,30)
C     CALCULLATE INTERMEDIATE VARIABLES
      IF(XTRM(I) .EQ. 0.0) GO TO 10
      W(I,4)=Z(I,1)
      IF(Z(I,1) .GT.XPLRM(I)) W(I,4)=XPLRM(I)
      IF(Z(I,1) .LT.XPLRMI(I)) W(I,4)=XPLRMI(I)
      W(I,2)=(W(I,1)-XC1(I)*W(I,4))/XTRM(I)
      W(I,3)=W(I,2)
      IF(W(I,2).GT.XRLRM(I)) W(I,3)=XRLRM(I)
      IF(W(I,2) .LT.XRLRMI(I)) W(I,3)=XRLRMI(I)
      GO TO 20
   10 W(I,4)=W(I,1)
   20 W(I,6)=((W(I,4)-(OM(I)/XR1(I)))*XK1(I))-(Z(I,4)*XK2(I))
      W(I,7)=Z(I,2)+XK4(I)*W(I,6)
      W(I,8)=W(I,7)
      IF(W(I,7) .GT. XLLM(I)) W(I,8)=XLLM(I)
      IF(W(I,7) .LT. XLLMI(I)) W(I,8)=XLLMI(I)
      W(I,9)=(W(I,10)-XIPL(I))*XIPLG(I)
      W(I,11)=W(I,8)
      IF(W(I,8) .GT. W(I,9)) W(I,11)=W(I,9)
      W(I,13)=Z(I,3)
      IF(Z(I,3) .GT. XPGM(I)) W(I,13)=XPGM(I)
      IF(Z(I,3) .LT. XPGMI(I)) W(I,13)=XPGMI(I)
      W(I,15)=W(I,13)*W(I,10)
      W(I,14)=(W(I,11)-W(I,13))/XTG(I)
      W(I,12)=W(I,14)
      IF(W(I,14) .GT. XRGM(I)) W(I,12)=XRGM(I)
      IF(W(I,14) .LT. XRGMI(I)) W(I,12)=XRGMI(I)
      W(I,17)=(XFHP(I)*Z(I,4)+XFIP(I)*Z(I,5)+XFLP(I)*Z(I,6))
      PM(I)=W(I,17)*XPBASE(I)/100.0
      W(I,19)=XTHS(I)-W(I,10)
      W(I,18)=(10.*Z(I,7))+(10.*XKP(I)*W(I,19))+Z(I,8)
      W(I,21)=W(I,18)+W(I,15)
      W(I,22)=W(I,21)
      IF(W(I,21) .GT.XGLM(I)) W(I,22)=XGLM(I)
      IF(W(I,21) .LT.XGLMI(I)) W(I,22)=XGLMI(I)
      W(I,23)=Z(I,9)
      F(I)=(1+OM(I))
      VTT(I)=CABS(VT(I))/VTO(I)
      AUX(I)=F(I)-(XKAUX(I)*F(I))*((1.0-VTT(I))**2)
      IF(F(I) .LT. XFMIN(I)) GO TO 110
      IF(VTT(I) .LT. XVMIN(I)) GO TO 110
      W(I,24)=AUX(I)*W(I,23)
      W(I,25)=W(I,24)-W(I,15)
      W(I,26)=Z(I,10)
      W(I,10)=W(I,26)-(XKSH(I)*(W(I,15)**2))
      GO TO 120
  110 AUX(I)=0.0
      PM(I)=0.0
C
C     CALCULATE INTEGRAL INPUT
C
  120 IF(XTRM(I) .EQ. 0.0) GO TO 30
      PLUG(I,21)=W(I,3)
   30 PLUG(I,22)=W(I,6)*XK3(I)
      PLUG(I,23)=W(I,12)
      PLUG(I,24)=(W(I,15)-Z(I,4))/XTHP(I)
      IF(XTIP(I) .EQ. 0.0) GO TO 40
```

```
      PLUG(I,25)=(Z(I,4)-Z(I,5))/XTIP(I)
      GO TO 50
   40 Z(I,5)=Z(I,4)
   50 IF(XTLP(I) .EQ. 0.0) GO TO 60
      PLUG(I,26)=(Z(I,5)-Z(I,6))/XTLP(I)
      GO TO 70
   60 Z(I,6)=Z(I,5)
   70 PLUG(I,27)=W(I,19)*XKI(I)
      PLUG(I,28)=(90.*Z(I,7)+90.*XKP(I)*W(I,19)-10.*Z(I,8))/XTR(I)
      PLUG(I,29)=(W(I,22)-W(I,23))/(XDE(I)+XTF(I))
      PLUG(I,30)=W(I,25)/XCD(I)
      PRTVAR(I,14)=W(I,10)
      PRTVAR(I,15)=W(I,15)
      PRTVAR(I,16)=W(I,26)
      PRTVAR(I,17)=W(I,22)
      RETURN
C
C     ENTER HERE TO CALCULATE INITIAL CONDITIONS
C
      ENTRY TRBLIC(I)
      VTO(I)=CABS(VT(I))
      PEO(I)=PM(I)*100./XPBASE(I)
      W(I,1)=PEO(I)
      W(I,10)=XTHS(I)
      OUT(I,21)=PEO(I)
      OUT(I,22)=PEO(I)
      IF(XK3(I) .EQ. 0.0) OUT(I,22)=0.0
      W(I,7)=OUT(I,22)+(PEO(I)*XK1(I)-PEO(I)*XK2(I))*XK4(I)
      W(I,8)=W(I,7)
      IF(W(I,7) .GT. XLLM(I)) W(I,8)=XLLM(I)
      IF(W(I,7) .LT. XLLMI(I)) W(I,8)=XLLMI(I)
      W(I,11)=W(I,8)
      OUT(I,23)=W(I,11)
      W(I,15)=OUT(I,23)*W(I,10)
      OUT(I,24)=W(I,15)
      OUT(I,25)=W(I,15)
      OUT(I,26)=W(I,15)
      OUT(I,27)=0.0
      OUT(I,28)=0.0
      OUT(I,29)=W(I,15)
      OUT(I,30)=W(I,10)+(XKSH(I)*(W(I,15)**2))
      IF(OUT(I,23) .GT. XPGM(I)) WRITE(6,100) I
      IF(OUT(I,23) .LT. XPGMI(I)) WRITE(6,100) I
  100 FORMAT('0 TURBINE GATE LIMIT EXCEEDED BY INITIAL POWER',
     S'ON UNIT',I3/)
      RETURN
      END

$ENTRY
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